CALIFORNIA
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COMMISSION

Distributed Generation Case Studies For Permit Streamlining and the Impact Upon Transmission and Distribution Services

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Preface

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Abstract

This multi-task report explores the benefits and obstacles to widespread Distributed Generation DG implementation in California. The report uses case studies as the basis for identifying the local obstacles and issues that revolve around DG siting, installation, and operation. It includes two case studies of very different potential host facilities, one a municipal recreational Aquatic Park and the other an industrial petroleum products refinery. The two case studies offer discussion-launching points, to better understand the benefit of streamlining DG installation processes. These two sites were economically and technically analyzed for DG installations, with comparisons drawn from the conclusions. This comparison is utilized to highlight the additional obstacles to permitting DG at an industrial facility, with reference to methods that might streamline the permitting process for both types of facilities.

The two case studies are then used as a vehicle to the discussion of additional barriers to wide spread distributed generation. The streamlining of environmental permitting, siting costs and procedures, and a discussion of the interaction between DG and the grid system of transmission and distribution are all approached. Solutions to the barriers of DG implementation, and explanations of the benefits to solving these problems are contained within this report.

The benefits to the grid system are realized in pricing strategies and services provided to the distribution system by DG's approach to problems in demand side management. The Engineering and Institutional limitations of DG as a means to provide Transmission and Distribution services highlight the cases where DG can and cannot benefit the grid system. The report explores opportunities to maximize the benefit of a DG approach to power needs.

Executive Summary

This report characterizes the market barriers and implications of Distributed Generation's (DG's) wide spread implementation in California. In 1999 the California Energy Commission chose to analyze the market barriers and implications to widespread implementation of Distributed Generation. The first part of the report deals with DG case studies for permit streamlining. The second part of the report examines the Impact of DG upon transmission and distribution services.

Distributed Generation Case Studies for Permit Streamlining

Heritage Park

Heritage Park is a municipally owned and operated recreational facility with three swimming pools. The facility once had a Combined Heat and Power (CHP) facility but after a two-year operation, Southern California Edison, the owner, dismantled the facility and capped the piping. Today, the facility remains an attractive site for CHP as a result of the swimming pool heating required and the consistent onsite need for electricity.

This analysis concentrated on the installation of a 60 kW Capstone microturbine. The reason this analysis concentrated on the microturbine option is due to several factors, including: the expense of fuel cells, the perceived past unreliable performance that Heritage experienced with reciprocating engines, the fact that regular combustion turbines were oversized for this application, and the potential opportunity for a free microturbine. The microturbine would exhaust into a heat exchanger that would generate hot water. This hot water would then in turn, heat the water for all three pools.

CHP is a good choice for Heritage Park. This study presumes that the current high rates will prevail until around 2004 and at that time the rates will fall to reflect the long-term contracts signed by the California Department of Water Resources. In the expected case, the envisioned project achieved an internal rate of return of over 30% with a simple payback of around two and a half years. The project proved somewhat sensitive to the price of gas. If it were to double, the rate of return would fall to 21%. Also investigated was the impact of nonbypassable surcharges to pay off the state's debt for past purchases of electricity. If these were imposed, the internal rate of return would fall by 10%.

Since microturbines in the size considered for Heritage Park are currently within the jurisdiction of the South Coast Air Quality Management District, permitting this facility is fairly straightforward. A modest budget of $2000 is sufficient for the time and fees necessary for the acquisition of the permits necessary.

Paramount Petroleum

The second CHP facility chosen for the Energy Commission's analysis is an industrial class combined heat and power (CHP) facility, both in terms of its physical and economic feasibility as well as challenges it faces through site permitting.

Paramount Petroleum was chosen for this study. They are in the process of installing a 6.5 MW CHP facility to raise steam for their process needs as well as power for their refinery. Combustion turbines were the only technology seriously considered for this application because of the high temperature nature of the thermal needs at the refinery. Other technologies such as micro turbines, reciprocating engines or fuel cells could not raise thermal energy at the temperatures needed on site.

Before Paramount Petroleum narrowed their selection down to a 6.5-MW combustion turbine (the "small" choice), they looked at larger sizes. The intermediate choice was a 25-MW combustion turbine/combined cycle plant. The large choice was a 50-MW (minus) combustion turbine.

The intermediate choice consisted of an aero-derivative combustion turbine that generated power through both a combustion turbine and a steam extraction turbine. The useful heat available for process would come from the intermediate pressure drum of the heat recovery steam generator (HRSG) and the extraction port of the steam extraction turbine. Only 20% or so of the power generated from this facility would be used on site. The balance would have to be sold to another party or on a wholesale market.

The 50-MW CHP plant considered would have heated a variety of refinery processes through the use of heat transfer fluids. Though this type of facility would have been perhaps the most aggressive in terms of energy conservation (the largest energy cascade available at the plant), only 10% of the power generated would have been used on site. In addition, this configuration presented control challenges that made the 50MW option less attractive.

Since this study was initiated, the California Public Utilities Commission ended open access so the only real market is with the California Power Authority or with a company who already has a contract with either the California Power Authority or the California Department of Water Resources. Paramount chose the less financially risky option and is building the 6.5 MW CHP facilities only to generate power for their own needs.

This new on site power generation finds itself in an economic environment characterized by the electric tariffs of Southern California Edison Company. The refinery itself is on an interruptible rate. Curtailments during 2000 and 2001 cost the refinery millions of dollars in penalties as they simply chose not to curtail when required to. They ultimately rented diesel standby units that cost approximately $750,000 per year in rent. They have returned the diesels, confident that their CHP system will keep them from future I-6 (agreements with the utility to pay an increased energy rate for any power used during a power shortage) penalties. This rental cost is an annual credit that needs to be included with the avoided electricity in order to calculate the economic performance of the new facility. This facility should earn a return on equity of around 30%. Its simple payback before taxes is 2.5 years. This is allowing for the currently high rates to abate somewhat after three years. This is remarkable considering special site challenges that have led to a fairly extraordinary capital cost exceeding $1500/kwh.

A sensitivity analysis was done. The project economics are sensitive to the cost of fuel to the point that with natural gas at $5/mmbtu (double that presumed for the expected case in this study) the economics become marginal. In addition, the impact of non-bypassable surcharges to recover the state's debt for power was considered. There was not one instance where the project remained economically viable were non-bypassable surcharges to become the state's policy.

Site permitting is always an issue for projects of this magnitude and Paramount Petroleum has been no exception. Care needed to be taken that the combustion turbine was not located within 1000 feet of a school or extraordinary noticing requirements would have been required. Emission credits had to be obtained to offset oxides of nitrogen emissions. Very expensive control emission equipment and continuous emission monitoring equipment had to be installed. Aesthetic requirements were imposed by the city of Paramount. A federal Title V application requiring changes in monitoring, record keeping and reporting was required.

DG Permit Streamlining

One of the major obstacles to successful deployment of distributed generation (DG) exists at the local permitting level. The primary local permit processes are conducted by multiple agencies, e.g., city and county governments, air districts. Obtaining approvals from these entities can be time-consuming and costly, as well as confusing to project developers who are not well versed in the local government requirements and procedures and to agency personnel who are not knowledgeable regarding DG technologies. Consequently, the deployment of DG may be hindered because of the involved and costly permit processes. In order to overcome these obstacles, the permit process must be understood, and opportunities to reduce confusion and costs should be developed.

The levels of government involvement and review and approval obstacles were presented in the California Energy Commission (Energy Commission) December 2000 report, "Distributed Generation: CEQA Review and Permit Streamlining" (P700-00-019). The three permit processes identified by the Energy Commission included land-use approvals, building permits and air permits with particular emphasis on the requirements for approval and permits, as well as opportunities identified to streamline the California Environmental Quality Act (CEQA) review and permitting processes. As a result of this effort, the Energy Commission Staff's recommendations (focused on assisting local governments) presented in last year's report included information dissemination (e.g., training, technical assistance, guidance development to local governments), amendments to the CEQA guidelines for certain categorical exemptions of select DG equipment, and involvement in inter-agency DG-related efforts (e.g., California Air Resources Board, local permitting jurisdictions, local government planning). However, the Energy

Commission's recommendation to focus on assistance to local governments rather than private DG developers was stated in last year's report as follows: "This approach would enable the Energy Commission to maintain its neutrality regarding the acceptability of individual DG projects, while still facilitating DG project deployment." Therefore, in order to identify potential obstacles and streamlining opportunities for DG project developers, an evaluation of two case studies was initiated.

Two case studies – DG project development at a municipality site and at an existing industrial site – are discussed in this report. The current permitting process and practices for each site were identified based on a series of discussions with local agencies and with site personnel. Furthermore, the permit process in other areas of California was also considered in order to present a broad-brush discussion of similarities and differences that may also be used to describe obstacles and streamlining opportunities. Recommended streamlining opportunities were based on previous Energy Commission efforts noted above and on discussions with agency and site personnel. From this information, cost savings opportunities for the two case studies were qualitatively assessed, and approximate statewide cost savings associated with the recommended streamlining opportunities were estimated based on a market assessment of combined heat and power in California. A rough estimate of nearly $70 million may be saved statewide over the next 15 years with improvements in the agency review and approval process. These improvements include useful resources and tools that can be developed, so project developers may access these in the early project planning and development phases in order to minimize project costs. Furthermore, the implementation of these resources and tools may provide certainty to the approval process not only for the agencies but also for the developers seeking project approval for projects throughout the state, thus facilitating the deployment of DG technologies in California.

The Impact of DG Upon Transmission and Distribution Services

Transmission System services provided by DG

Many studies, reports and industry experts in the field of distributed generation (DG)[1] broadly refer to the benefits that DG can provide to transmission and distribution systems. This report provides a qualitative analysis of the issues that drive the impacts and benefits DG on the transmission system. A companion study to this report identifies the services that DG can provide to distribution systems.[2] The objective of this report is to identify transmission services that DG is technically capable of providing, and to develop guidelines that will enable DG to participate in markets for these services given the technical and operational requirements of the system.

The amount of generation relative to the system total load, or penetration, is the most important factor for the influence of DG on transmission operation. A single 2 MW generator may have considerable impact on the operation of a distribution system, while going wholly unnoticed on the transmission system.[3] On the other end of the spectrum, if a fully mature DG market results in 30% or more of the total customer load supply, the impact and importance to transmission operation will be undeniable. A tougher question is what the impacts are at penetration levels between the two extremes, and how they should be treated with respect to considerations of both system control and economic valuation. This question is addressed by focusing on both the localized transmission benefits that a relatively small penetration of well-sited DG can provide, and the benefits to the larger transmission system as a whole that can feasibly be achieved by growing DG penetrations.

FERC Order 888[4] established the definitions for generation related ancillary services for bulk transmission, and these definitions have been adopted throughout North American power markets. The California Independent System Operator (ISO) purchases and provides the ancillary services that are required for bulk transmission transactions in California, including specifying technical and operational requirements for the generators that provide those services. This report discusses the transmission benefits of DG in the context of California markets, and hence focuses on the ancillary service definitions and practices in use, and proposed for, the California market. In addition to discussing the capability of DG to provide ancillary services, this report identifies additional transmission related benefits that can be provided by DG, and concludes with a discussion of issues that will impact the degree to which DG can penetrate each of these transmission services markets.

The remainder of this report is organized into three major sections:
1) An overview of transmission level services that can be provided by distribution interconnected DG;
2) Detail descriptions of DG transmission services; and
3) Guidelines for DG participation and penetration.

Benefits of DG to the distribution system

There is increasing recognition among distributed resource technology manufacturers and owners as well as in the electric utility industry that distributed generation (DG) is technically capable of reducing costs and improving performance of electric distribution systems. The provision of electricity distribution services consists of many "bundled" services, which under today's utility market and regulatory environment are provided to customers under a single service definition and price. This report identifies the components distribution service that DG are technically capable of providing, and develops pricing strategies to compensate DG technologies for the economic benefit that they can offer to utility distribution companies.

This report identifies eight services that distributed generation can provide to the distribution system. These services are:

1) Capacity support;
2) Contingency capacity support;
3) Reduction of losses;
4) Voltage support;
5) Voltage regulation;
6) Power factor control;
7) Phase balancing; and
8) Equipment life extension.

The ability of DG to provide these services is dependent on the type of DG installation. So called "behind the meter DG" that reduces customer loads at the meter, DG generators not connected to customer loads (DG connected directly to the distribution system), and customer-side demand management measures (DSM) have differing technical capabilities to provide these services.

These distribution services can be divided in three types (Executive Summary Table): those that substitute or defer investment in major capital assets; those that provide power quality control functions; and those that substitute for energy purchases. The choice of pricing strategy for each of these services is largely driven by the type of service.

Executive Summary Table of Distribution Services

Asset Substitute	Power Quality	Energy
Capacity support	Voltage support	Losses
Contingency capacity support	Voltage regulation	
Equipment life extension	Power factor control	
	Phase balancing	

This report evaluated three pricing mechanisms for distribution services: 1) bilateral agreements, 2) RFP/auction competitive procurements, and 3) posted tariffs. The recommended pricing approaches are derived by matching the attributes of the service categories to the features of the different pricing mechanisms. The major conclusions of the assessment of pricing mechanisms are listed below.

1) Bilateral agreements should rarely be used because they are likely to result in inefficient prices and can limit innovation and potential cost savings. Bilateral agreements may be appropriate for some DSM applications to overcome saturation and persistence issues with energy efficiency measures.
2) The scale of most large asset-based distribution requirements favors the RFP/auction approach where there is sufficient lead time and DG benefit to

accommodate the timing and administrative costs of a competitive pricing mechanism. For routine procurements, steps can be taken to reduce the administrative burden and to encourage DG participation.

3) Services that provide power quality control functions and energy-based services are most effectively priced using a posted tariff. This recommendation is driven primarily by the relatively small and dispersed nature of expenditures (both capital and expense) for quality control, short response time, relatively minor impact of partial participation by DG owners, and the existence of tariffs for some components.

Procuring distribution services requires clear definition of the contract structure, the contract terms, and the mechanism by which the price and quantity levels are determined. Poorly designed pricing mechanisms and contracting forms can eliminate otherwise cost effective opportunities for DG to participate in providing distribution services. Adopting appropriate pricing approaches for distribution services has the potential to lower UDC costs of service and provide DG owners/operators the opportunity to share in the benefits they can provide to the distribution system.

Engineering DG to Provide T&D Services

DG's ability to provide transmission and distribution services are hampered by technical limitations, business practices, and regulatory and legal constraints. "Technical limitations" refer to the ability of various DG technologies to satisfactorily fulfill the engineering requirements for each T&D service. Business practices and regulatory and legal constraints are institutional in nature. Technical innovation, learning and improved procedures by utilities, and ongoing regulatory evolution are improving DG's opportunities to overcome such barriers.

There are three fundamental ways that these limitations impact effective participation by DG in providing T&D services. The proposed service may be:

- Unfeasible- DG is technically incapable of providing the service;
- Unprofitable - it is too costly for DG to comply with technical or institutional constraints; or
- Prohibited- it is contractually or legally restricted for DG to provide the services.

This section of the report goes on to briefly review the T&D services identified in Tasks 2.1 and 2.2. as well as the technical limitations, DG capabilities and service requirements. A discussion of the limitations due to DG's Impact on Distribution System Facilities and Operations and some of the institutional limitations: business practices and regulatory rules are included in the scope of this section.

Technical Alternatives And Economic Comparison Heritage Park Aquatic Center/City Of Irvine

Summary

In 1999 the California Energy Commission chose to investigate the market barriers and implications to widespread implementation of Distributed Generation. Part of this investigation is the analysis of a Combined Heat and Power (CHP) facility. This analysis is for a small municipal facility in terms of its physical and economic feasibility as well as challenges it faces through site permitting.

Heritage Park is a municipally owned and operated recreational facility with three swimming pools. The facility once had a CHP facility but after a two-year operation, Southern California Edison, the owner, dismantled the facility and capped the piping. Today, the facility remains an attractive site for CHP as a result of the swimming pool heating required and the consistent onsite need for electricity.

This analysis concentrated on the installation of a 60 kW Capstone microturbine. The reason this analysis concentrated on the microturbine option is due to several factors, including: the expense of fuel cells, the perceived past unreliable performance that Heritage experienced with reciprocating engines, the fact that regular combustion turbines were oversized for this application, and the potential opportunity for a free microturbine. The microturbine would exhaust into a heat exchanger that would generate hot water. This hot water would then in turn, heat the water for all three pools.

CHP is a good choice for Heritage Park. This study presumes that the current high rates will prevail until around 2004 and at that time the rates will fall to reflect the long-term contracts signed by the California Department of Water Resources. In the expected case, the envisioned project achieved an internal rate of return of over 30% with a simple payback of around two and a half years. The project proved somewhat sensitive to the price of gas. If it were to double, the rate of return would fall to 21%. Also investigated was the impact of nonbypassable surcharges to pay off the state's debt for past purchases of electricity. If these were imposed, the internal rate of return would fall to 20%.

Since microturbines in the size considered for Heritage Park are currently within the jurisdiction of the South Coast Air Quality Management District, permitting this facility is straightforward. A modest budget of $2000 is sufficient for the time and fees necessary for the acquisition of the permits necessary.

Introduction

This report reflects a 1999 decision by the California Energy Commission to investigate the market barriers and implications to widespread implementation of Distributed Generation. One of its strategies was to investigate two separate project sites in order to analyze the permitting costs and time requirements for CHP applications. Two sites were chosen. The first is a municipally owned and operated swimming complex and the second is a large asphalt refinery. It was anticipated that these two projects would be different in nature, size and other characteristics and would serve to illustrate the similarities and differences in the permitting process required to make both of them viable.

Recreational Facility Site Description

Heritage Park is a municipally owned and operated recreational facility located at 4601 Walnut Avenue in the City of Irvine. It consists of 2.6 acres of landscaped and paved facilities and includes three swimming pools. There is a 50-meter pool, a 33_-meter pool, and a 25-yard pool. The site layout is shown in Exhibit 1. The largest pool is used for competition and swim meets, and synchronized swimming. The 33-meter pool is used to train diving competitors, and the smallest pool is mostly used for recreation.

The facility was constructed in 1974. It currently operates from 7:00 AM to 10:00 PM year round and serves approximately 500-600 patrons per day during peak periods offering regular usage and planned events annually. The community's suitability for a CHP project, its highly visible location, and the significant use seen by this facility prompted the analysis team to choose this site as a demonstration site. The demonstration value of a project at this site goes well beyond the economic merits of the energy savings and the increased efficiency.

Heritage Park has undergone many changes. The chlorination system has changed. The electric metering was expanded to include the city's tennis courts and stadium. The City of Irvine has undertaken an ambitious plan to upgrade the site, as of September of 1999. The master plan includes extending the 33-meter pool to 50 meters. It also includes the possibility of replacing the dive platforms. Also part of the plan is the demolition, relocation, or upgrading the existing buildings. This includes the observation tower and locker rooms, and replacing the original aluminum shell pool construction with new concrete construction.

In 1986 the City of Irvine commissioned a study, performed by Cogeneration Power Company Inc. to evaluate the feasibility of installing a cogeneration project at the site. The study concluded that it was economically feasible for the city to proceed with the project, with sales of excess power to the grid during peak periods. The conceptual design also included sales to the adjacent facility (Irvine High School) with an additional load of 150 kW and another million kWh of electric consumption per year. Annual gas consumption for the aquatics complex alone was 215,500 therms at 65 cents per therm, for an annual natural gas cost of just over $140,000. Electrical consumption was just over 425,000kWh per year at a cost of $39,000. It was this mismatch of low electric load to high thermal load that led the city to seriously consider adding electrical sales to the adjacent Irvine High School and/or sales of excess power to Southern California Edison's grid. SCE, opposed the sale of power to the high school, presented its own proposal for a cogeneration project when the City of Irvine invited 45 companies to propose such a project.

The city chose SCE's proposal in order to forestall some of the potential objections from SCE (despite the fact that SCE did not include sales to the high school), and because SCE proposed to build, own, and operate the facility. A 120 kW cogeneration system was installed and commissioned in 1989 but was subsequently shut down and removed two years after its startup. Various reasons have been cited for this, including equipment problems, and poor avoided cost performance[5]. The equipment was removed, the piping capped, and all that remains is a well built sound attenuated structure at the site.

Thermal loads at Heritage Park Aquatics Complex have changed slightly since its original construction. These loads are primarily served by 2 boilers, rated at one million BTU each, which supply enough heat to maintain the pools at 79° F. The boilers are natural gas fired. The electrical loads are mostly in the diatomaceous earth vacuum filtration system, walkway lighting, and operation of space cooling.

Onsite learned that there was no 15-minute data available for Heritage Park. In addition, it appears that the maximum site electrical demand increased from 250 kW to the current peak of 350 kW, which is not seasonal in nature. The site contribution of lighting loads from the Tennis Courts and the Stadium Lights have added to this peak. During the summer usage of the stadium diminishes. Daylight hours require less use of the walkway lighting. However, the peak is registered during each month and there is little significant variation in the kWh usage at this site year round. Onsite created a 24-hour profile in order to finalize its analysis, based on an assessment of site equipment and scheduling information provided by the staff at HPAC.

The aluminum structure pools at Heritage Park are at, or exceeding, their expected life and the continuation of operations will definitely depend upon rehabilitation of the facility. In light of recent events, Onsite, in conjunction with the City of Irvine decided to proceed with the feasibility evaluation for a CHP project at Heritage Park.

Technical Analysis

Energy Consumption Profiles

Current electrical usage at the Heritage Park site averages about 100 kW, with peaks in the order of 350kW. The pool pumps, the lighting, and ancillary electrical equipment of the aquatic facility make up the load. It was Onsite's plan to use the building site that remains from the former cogeneration project.

Natural gas consumption increases significantly during the winter months due to the continuous requirement of maintaining the pool water at 79 degrees Fahrenheit. The same seasonal variation is not observed for the electrical consumption, which remains within 28 percent variation between summer and winter usage. The main baseload electrical consumption resides in the pool pumps and vacuum filtration system, which operate continuously. Marginal load variations will occur due to event scheduling, patron usage, or other factors. The electrical load was construed as a base load for design purposes, despite the marginal load variations. It is important to note that there is a single electric meter serving the Aquatic Center, Tennis Courts, the walkway lighting, and the Stadium in the Heritage Park Complex. Thus, the peak demand is a composite of these loads. We observe that in the summer months, the peak demand decreases by an average of 100 kW. During scheduled maintenance periods (2–3 weeks per year) each of the three pools are shutdown sequentially.

This situation presents two alternative scenarios for the conceptual design of a CHP generation project at Heritage Park. The first option is to size the equipment to the baseload electrical demand, which is currently at just less than 100kW, and to supplement the additional heat and power requirements with natural gas purchases and supplemental electrical power as required. The second option would be to size the power generation equipment closer to the increased winter thermal loads and to sell and/or transfer the excess electricity to an adjacent facility. This would leave Heritage Park with excess recovered heat during the summer months, which would be "dumped" or could potentially be used to satisfy a cooling load through absorption cooling. With little opportunity to sell power profitably off site[6] and the low minimum loads (thermal and electrical) at Heritage Park, Onsite concluded that a smaller, base loaded system, configured with a microturbine[7] had the best possibility in terms of cost and benefits.

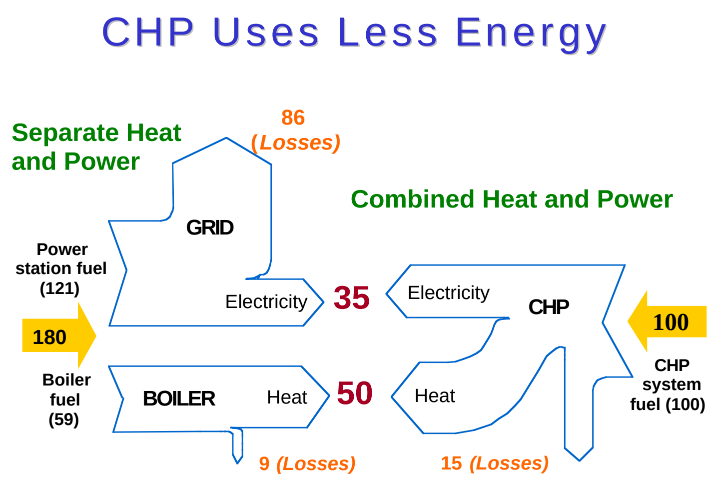
Distributed Generation

Distributed Generation (DG) is defined here as generation located at or near the load. Projects are generally developed by either the user to avoid the purchase of power from the grid or an energy service provider who then retails the power to the site. CHP is considered a subset of DG and can be used when there is a profitable use of the thermal energy; such is the case with Heritage Park.

Combined Heat and Power

CHP (cogeneration) is an energy cascade that captures energy normally rejected and provides a useful purpose. Figure 1 illustrates the concept. In the traditional case, steam is raised with a boiler on site and power is purchased from the local utility. The boiler requires 59 units of energy input to raise 50 units of useful steam. In the example shown, the utility requires 121 units of energy in order to generate 39 units of useful electrical energy[8]. A vast majority of the energy shown as lost is unavoidable as a result of the 2nd Law of Thermodynamics[9]. On the other hand, CHP as an energy cascade, uses energy that would ordinarily be 2nd law losses for another useful purpose. As can be seen in the illustration, with CHP, the losses can be held to only 15 units of energy.

***Figure 1. CHP Comparison*[10]**



The efficiency comparison is an aggregate 47% for the traditional means by which to provide electrical power and steam to one's facility compared to 85% through the use of CHP.

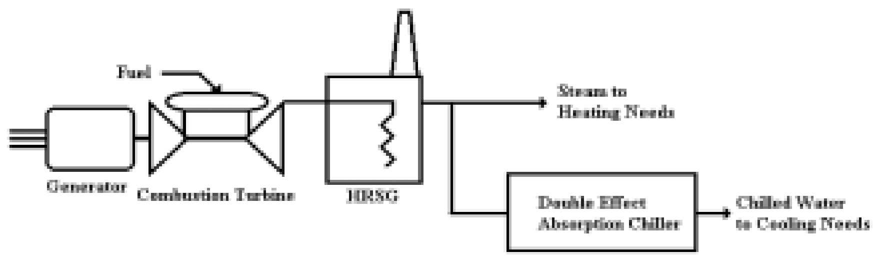
Prime Movers

The prime movers used to provide shaft power to generators come in two broad categories – reciprocating engines and turbines. Perhaps it will be soon that fuel cells will make a significant entrance on the CHP stage but they are not yet ready for primetime.

Combustion Turbines

Figure 2 illustrates the use of a combustion turbine in a CHP application.

Figure 2. Combustion Turbine Based CHP



The smallest of these is currently 500 kW. In an approximate way, a combustion turbine's heat rate[11] varies inversely with size. This means that as the smallest of the large combustion turbines, the 500 kW units have the worse efficiency. Emissions are usually controlled on combustion turbines with selective catalytic combustion. The development of emission control for combustion turbines is dynamic, however, there is at least one manufacturer using catalytic combustion and achieving similar emission results.

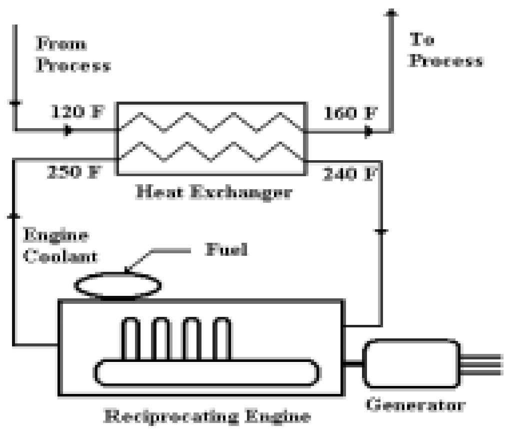
Combustion turbines can provide higher quality heat than reciprocating engines with available steam pressures exceeding 650 psig[12]. The steam produced can be used for process needs, building heating or in double effect[13] absorption chillers to produce chilled water. As a class, at least in the smaller size ranges, their heat rates are higher than for reciprocating engines. A fairly large turbine, GE's LM 6000 42 mw combustion turbine, has an efficiency that will meet or exceed virtually any reciprocating engine. In addition, there are manufacturers that are developing combustion turbines with recuperation (see explanation below in the discussion of microturbines) and these machines also have efficiencies that approach 40%.

The smallest combustion turbine was too large for this project. In addition there was little need for the high quality heat available from the exhaust and therefore little reason to tolerate the lack of efficiency of a relatively small combustion turbine.

Reciprocating Engines

In terms of numbers, the vast majority of the CHP facilities being installed are with reciprocating engines. Usually the fuel is natural gas. Figure 3 illustrates the concept.

Figure 3. Reciprocating Engine Based CHP



The drawing is simplified. The fact that heat is available from the exhaust and oil cooler as well as the engine block is not graphically depicted. Heat from a reciprocating engine can be either in the form of hot water or low-pressure steam (15 psig or less). The phase change from liquid to steam can either take place within the engine or in a drum separate from the engine. The hot water or steam can be used for process needs, building heat, to heat potable hot water or to generate chilled water in an absorption chiller.

There are two broad categories of reciprocating engines. The first category is automotive derivative engines and the second category is industrial engines. Industrial grade engines dominate the larger size. In the larger sizes, engines can either be "rich burn" or rely on a stoichiometric mixture (balanced air fuel ratio), or "lean burn" with significant excess air. Up until recently lean burn engines could not be easily controlled to the tight emissions standards in the state of California, though they were inherently cleaner and more efficient than rich burn. This has changed with the application of selective catalytic reduction. The change does come at a significant cost penalty, particularly in the small sizes (<500 kW).

Rich burn engine emissions can be controlled through the use of a three-way catalyst (NO_X, CO and unburned hydrocarbons) and a fuel ratio controller that will tightly control the engine's fuel mixture. Most industrial engines got their start as diesel or compression ignition engines. This is important to note because it indicates their rugged design that results naturally from the high compression ratio required of compression ignition engines.

In the smaller sized projects (< 200 kW), both industrial and auto derivative engines are found. These projects generally produce power and hot water. The auto derivative engines are generally beefed up with stronger valves and there are CHP facilities that have had good luck with them. They are not as robust as the industrial grade engines referred to earlier. Even though their cost is competitive (≈ \$1500 - \$1700/kw in this size range), reciprocating engines were dropped early as an appropriate prime mover for this project, due to the aforementioned experience of the city with reciprocating engines as well as the potential availability of a subsidized microturbine.

Fuel Cells

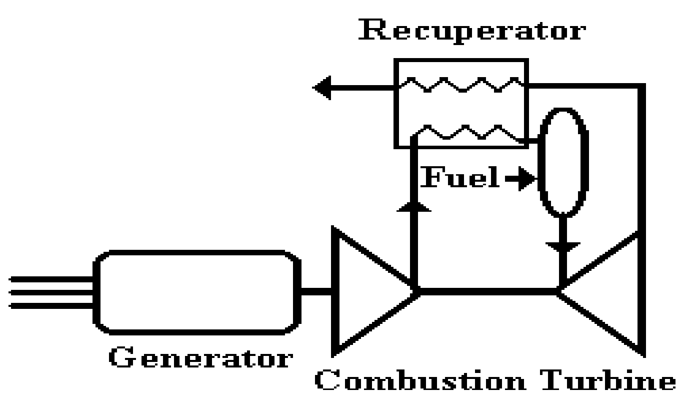
Fuel cells remain a promise. The only one commercially available is a 200 kW size (far too big for this project) and is very expensive to buy and maintain. Other technologies remain in development. The proton exchange membrane (PEM) fuel cells are simple to make but require very pure hydrogen. Hydrogen gas cannot be produced from wells like oil or gas and therefore has to be made through a complicated reformation process of natural gas, alcohol or gasoline. Mass-producing small reformers has been a challenge for the industry.

Solid oxide fuel cells do not require the fuel conditioning that PEM fuel cells require but these fuel cells are themselves difficult to fabricate. The good news is that they are very efficient (around 50%) and are being tested with microturbines to develop an exceedingly high efficient hybrid cycle (65 to 75%). Recently, molten carbonate fuel cells have emerged as a leading technology. All fuel cells have the added advantage that by nature, they are all very clean when it comes to their emissions. However, the industry waits anxiously for the promise of fuel cells to come to fruition. Fuel cells, due to their high costs ($6,789.90/kw) were not considered in this analysis.

Microturbines

A microturbine is a small combustion turbine (some may be as big as 400 kW). The turbine spins very fast at speeds between 50,000 rpm and 100,000 rpm. This keeps their size small. As was mentioned before, small combustion turbines are intrinsically inefficient. Therefore microturbines come with a recuperator. This, along with their size, typically distinguishes them. Figure 4 illustrates a microturbine.

Figure 4. Microturbine



Air first enters the microturbine's compressor[14]. Upon passing out of the compressor the air enters the recuperator and is heated. The air then goes into the combustor[15] where fuel is added for combustion. The results of combustion are expanded through the turbine to provide shaft energy to both the compressor and the generator. The exhaust from the turbine passes through the other side of the recuperator (thus providing the energy to heat the air coming out of the compressor). The microturbine's exhaust then leaves the recuperator at around 500 F.

In CHP analyses, the microturbine performs like the reciprocating engine described above, but perhaps with a slightly higher heat rate. The 500 F exhaust limits the heat made available to generally low quality[16] needs. The microturbine has fewer parts, which lead to the following value proposition. This value proposition is that a microturbine has the efficiency of a reciprocating engine but should be cheaper to build and cheaper to maintain because of its simplicity. Microturbines are just becoming commercially available. Manufacturers are anxious to retrieve their development cost so the cost of purchasing the machines remains stubbornly high. Maintenance costs should come down as the manufacturers become more confident in just how much those costs are going to be. The microturbine was the technology envisioned for this project and a detailed cost is provided below.

Economic Analysis

The Price of Energy

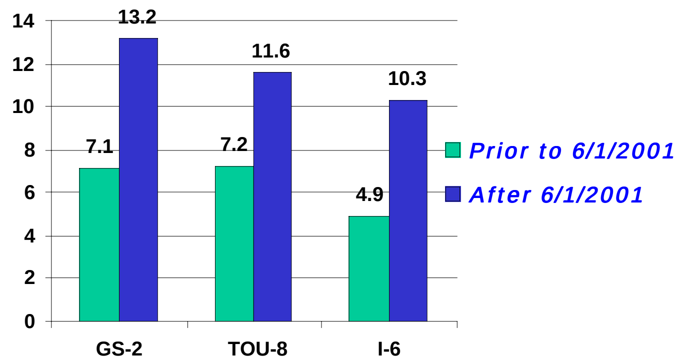
The Price of Natural Gas

Anomalous conditions existed prior this winter that lead to some fairly drastic price excursions for the price of natural gas in California. There are a number of explanations for this but a general consensus is emerging that the basis at the Arizona border that led to these prices was, in and of itself, anomalous. For the purposes of this study, SoCalGas' forecasted weighted average cost of gas (WACOG[17]) in the 2000 California Gas Report would be used as a proxy commodity cost of gas in California. This forecasted price averages around \$2.50/mmbtu. A second case will assume that it doubles to \$5.00/mmbtu/hr for the period in question (10 years). For the fuel that is avoided in hot water heaters and the pool heater, the SoCalGas tariff presumed will be GN-10. For the prime mover fuel, the tariff will be GT-F5.

The Price of Electricity

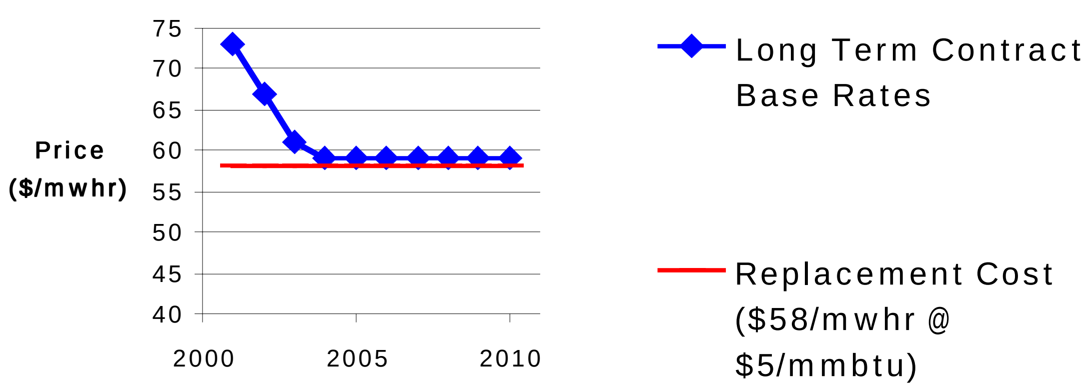
A number of things have worked together to stabilize the price of electricity. Unfortunately, most of these factors have worked to keep the price high. On June 1, 2001, the California Public Utility Commission was forced to raise electric rates for most of the customers of the state's investor-owned utilities. Though residential rates were increased significantly, commercial and industrial rates were increased even more. Figure 5, illustrates the effect on SCE's avoidable rate[18] of the June 1, 2001 rate increase.

***Figure 5. SCE Avoidable Rates*[19][20]**



For the purposes of this study, these higher rates will remain in effect for three years. However, it is Onsite's opinion that these rates overstate the real cost of electricity. The real commodity cost of electricity will track the average wholesale price of energy over the period in question plus a surcharge that must be collected to retire debt incurred for power already purchased. The weighted average cost of electricity purchased by the California Department of Water Resources serves as an excellent proxy for the long-term wholesale cost of energy. Using summary data obtained from the State Controller's website, Figure 6 illustrates these average weighted prices for each year in question.

***Figure 6. Weighted Average Cost of Long Term Power in California*[21]**



It can be seen that this weighted average cost of energy is $59/mwhr. Indicated also on Figure 6 is the replacement cost of power assuming $5/mmbtu natural gas. This is the cost of capitalizing and fueling a new combined cycle power plant with $5/mmbtu natural gas. Interestingly, the weighted average cost of electricity in the long-term contracts converges on this price. It would seem that there are others who believe that the long-term price of natural gas will be $5/mmbtu[22]. With regard to the surcharge, it appears certain that only the commercial and industrial customers will pay this surcharge. Table 1 illustrates how this surcharge was estimated.

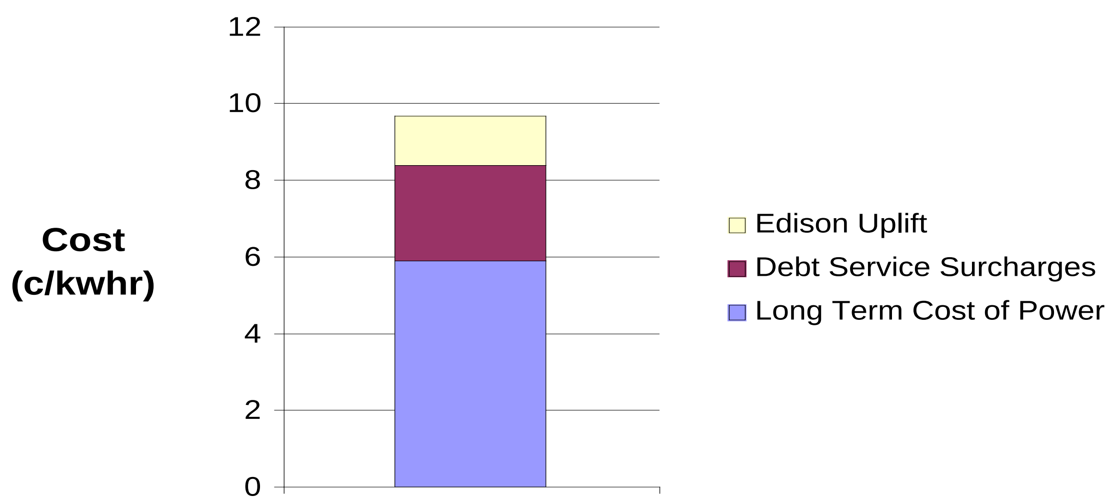
Table 1. The Surcharge Necessary to Service the Bonds[23]

	Amount	Interest	Time to Maturity	Annual Annuity
State Bond	$13,500,000,000	8.00%	15	$1,577,198,857
Utility Bond	$3,500,000,000	11.00%	15	$486,728,338
			Total:	**$2,063,927,195**

		State Surcharge	Utility Surcharge	Total Surcharge
1988 kwh Volume:	77,367,591,412	0.02039	0.00629	0.02668
1988 kwh Volume plus 7%:	82,783,322,811	0.01905	0.00588	**0.02493**

The loads used in the prior table are the loads of all of the customers, of all the investor owned utilities, with demands exceeding 20 kW for 1988. Assuming a 7% growth in load to December 1, 2001, it can be seen that a surcharge of 2.5 c/kWH will need to be collected to service the debt. To convert the long-term weighted average cost of electricity plus the surcharge necessary to retire past power purchasing debt, one must account for the utility's cost of uplift (line loss, settlement cost, etc). A data point is available from Southern California Edison for the spring of 2000. In July of that year, SCE filed for post transition rates with the California Public Utilities Commission, with an average cost of energy that exceeded the PX's average price for the same period by 22%. This will be presumed as the utility's cost of uplift. Figure 7 illustrates Onsite's estimate of the long-term retail rate for the period in question.

Figure 7. Aggregate Average Retail Energy Rate[24] ***from 2004 to 2010***



GS-2 is a two-tiered rate that Heritage Park pays for power. The average cost of retail energy above must be split into retail energy rates for these two tiers. This is accomplished by "force fitting" the above average retail rate to reflect the relationship between the current energy rates for the two tiers adjusted for the class average load in each of the tiers. Table 2 presents Onsite's forecast for the energy rates.

Table 2. Forecasted Edison GS-2 Rate

	2001 - 2003	2004-2010
Tier 1 (c/kWh for 1st 300 kWh/kW of demand	11.94	9.68
Tier 2 (c/kWh for balance of consumption	13.48	10.55

There are two more issues that need to be dealt with. The first issue is that Edison's GS-2 rate was a declining block rate that would reward consumers for maintaining a high load factor. In the past, the second tier was significantly cheaper than the first tier. Developers installing CHP would find themselves aggravating the consumers load factor and therefore, they would be constantly competing with the lower rate rather than the higher one. On June 1st, 2001, the Commission signaled that they wanted an inclining block rate, to encourage conservation. It can be anticipated that a more rational rate will be put into place at some point during the proposed project's life. However, if the current load factor remains for the customer, then the economics will be improved because this consumer's entire load is in the first tier where the rate would normally be higher. This is the case before the installation of a CHP system and it will be the case after the installation.

The second issue deals with the surcharge necessary to service the debt incurred as a result of the power purchased previously. It will be the investor owned utilities' contention that this surcharge should be collected on a nonbypassable basis. In fact, the Assembly passed a bill[25] calling for this surcharge to be nonbypassable for all but 250 mw of new onsite generation being added each year. If this surcharge is not bypassable, it will have a significantly negative impact on the project being discussed here. That impact will be measured in this analysis.

Project Description

The project envisioned for Heritage Park initially consists of Capstone 60 kW microturbine and a heat recovery hot water heat exchanger. Figure 8 illustrates the concept and presents the contribution of the microturbine to the facility's power requirement. Figure 9 presents the microturbine's contribution to the facility's thermal requirements. The hot water from the heat recovery hot water heat exchanger will be used exclusively to heat the swimming pools thus reducing the natural gas consumption of the existing pool heaters. This is depicted in Figure 10. The microturbine will be interconnected in parallel with the electric utility service. In compliance with Edison's Rule 21, on-board interfacing hardware will make this interconnection fairly simple.

Figure 8. The Cogeneration System

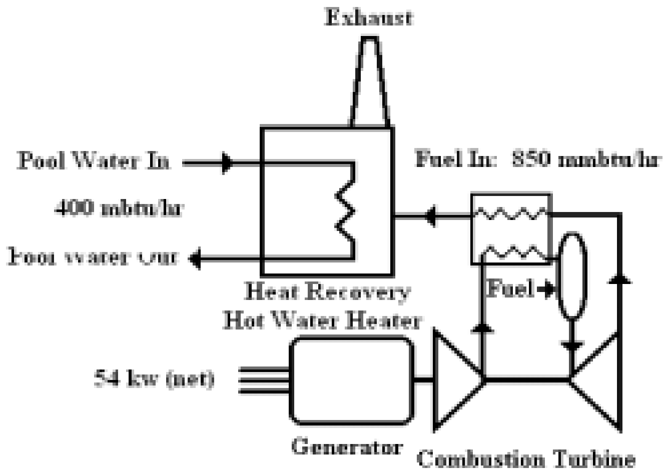


Figure 9. Facilities Electrical Profile[26]

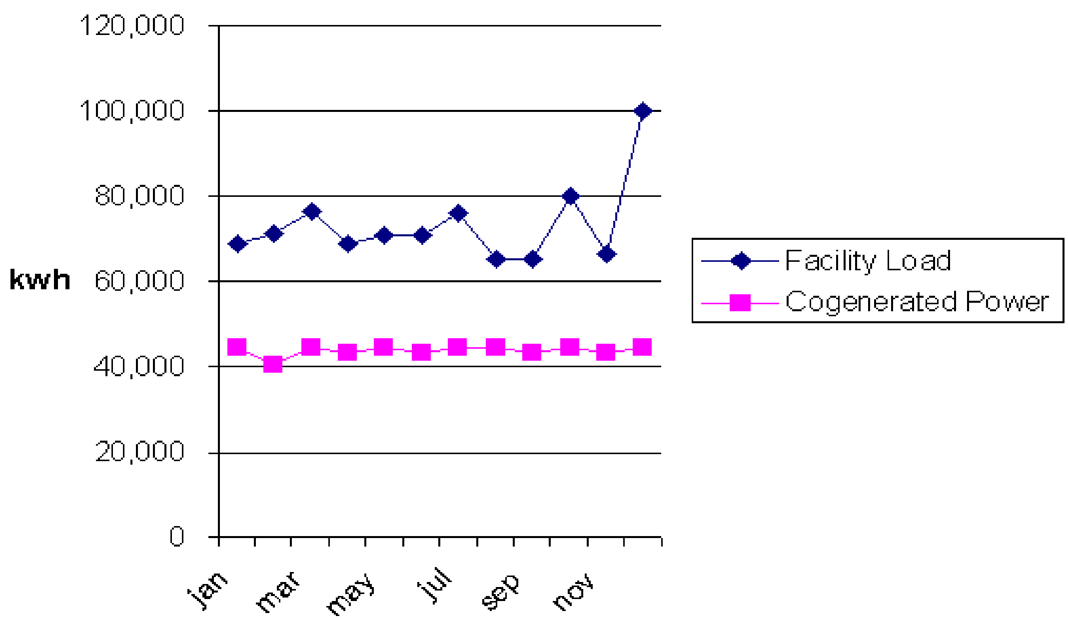
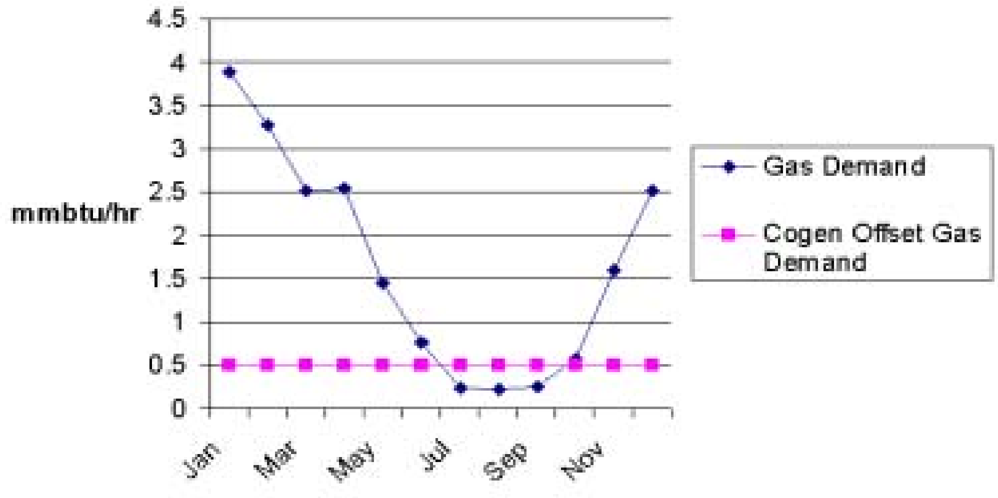


Figure 10. Facility Thermal Requirements



Permitting

Permitting for this project is covered more in-depth in an accompanying report prepared under SEP-2 Task 1.2. Given the City of Irvine's efforts to streamline permitting and provide one stop processing, the time would be spent only in preparing the documents. Broadly, the following issues must be dealt with regarding permitting:

- Obtaining local jurisdiction pre-construction and construction approvals
  - Planning department land use and environmental assessment/review
  - Building department review and approval of project design and engineering
  - Air district approval for construction
- Obtaining local distribution company approval
  - Interconnection study
  - Natural gas pipeline connection/supply
- Obtaining local jurisdiction post-construction and operation approvals
  - Planning department and building department confirmation and inspection of installed DG source
- Air district confirmation that DG emissions meet emissions requirements

The following are agencies that need to be accommodated for a microturbine to be sited at Heritage Park:

Agency Contacted	**Jurisdiction**
City of Irvine Community Development Department	Planning Services Division (Aesthetics, land use and zoning) Building Services Division (Building safety and codes, gas connection)
Orange County Fire Authority	Fire Safety
South Coast Air Quality Management District	Air Quality

Regarding air quality, the selection of a microturbine avoided the need for an air permit as it is below the exemption level for combustion turbines.

Capital Estimate

The capital estimate of the project is presented in Table 3.

Table 3. Capital Cost Estimate

Item	**Estimated Cost**
Generator Package (60 kW Capstone)	$49,000
Heat Recovery Hot Water Heater	$7,895
Fuel Gas Compressor	$6,375
Grid Interconnection	$8,000
Installation	$22,000
Engineering	$8,000
Permitting	$2,000
Contingency	$5,064
Total	**$108,334**

Life Cycle Evaluation

The cost of energy was discussed above. The following assumptions will be used for the Expected Case:

Table 4. Economic Assumptions for Expected Case

Assumption	Value
Installed Cost	$108,334
Commodity Rate for Fuel ($/MMBtu)	$2.50
Pool Heater Natural Gas Tariff	SoCalGas GN-10
Cogeneration Gas Transportation Tariff	SoCalGas GTF-5
Current Electric Rate Tariff	Edison GS-2
Period for Current Tariff	First 3 Years
Long Term Wholesale Price of Power ($/mWh)	$59

Discussion

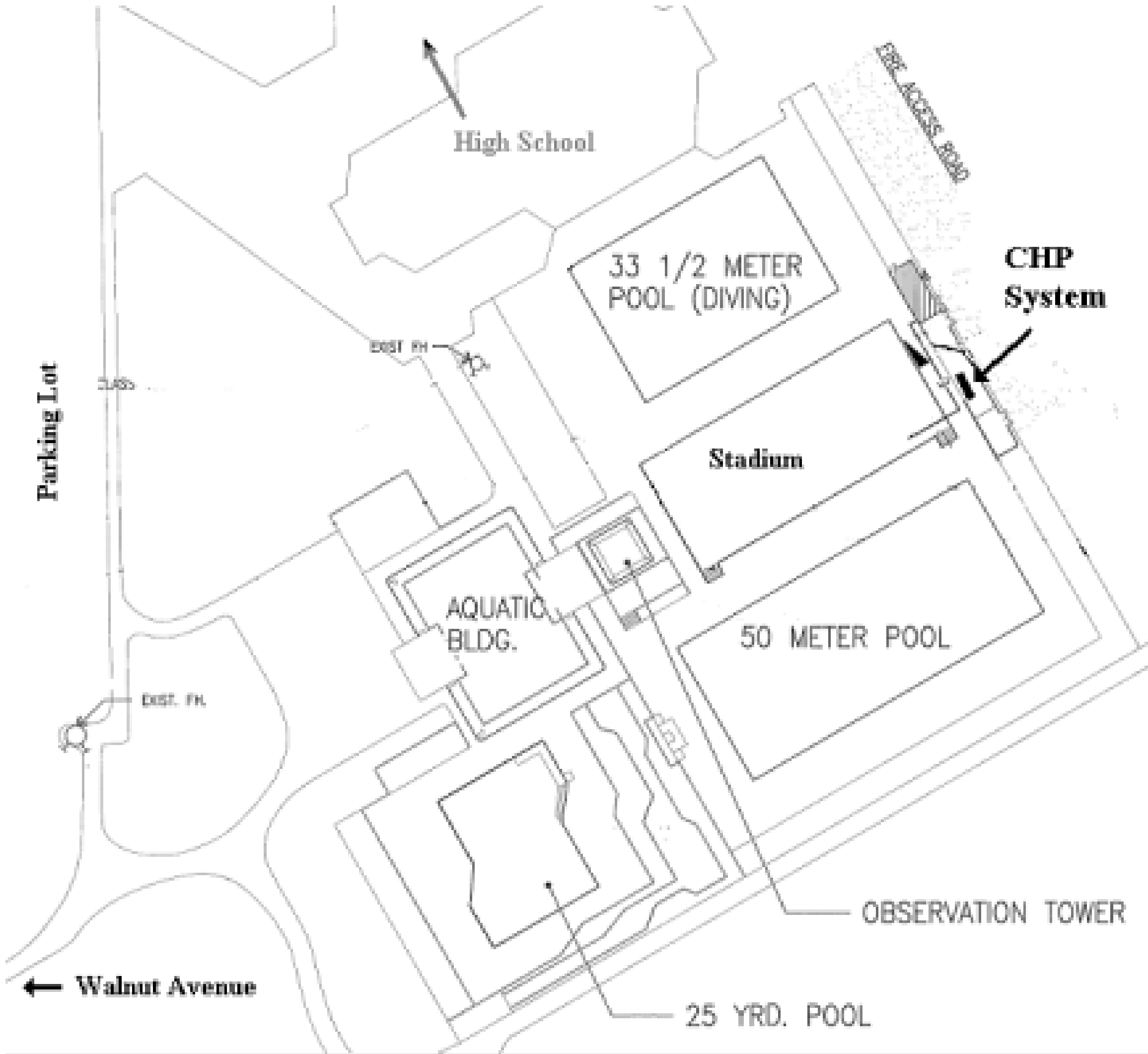
The results in Table 5 are remarkable. Any project built today could return its installed cost within 3 years. Even when the rates drop to what Onsite believes to be their long-term levels, the projects are still amply rewarding their investors. This stubbornly robust economic performance can be explained by the astoundingly high electric rates that will exist for the next several years. Given the fact that high electric rates have been framed into the infrastructure for the next ten years because of the long-term contracts signed by the California Department of Water Resources, projects such as these are going to remain excellent investments for their developers for a long time. These projects are sensitive to the price of fuel. This is particularly true during the period where the electric rates are expected to drop to anticipate long-term levels. A storm cloud may be on the horizon. If it is decided that projects such as these are forced to pay a non-bypassable surcharge to service the debt created by previous power purchases, these projects could lose their exemplary economics.

Table 5 is a compendium of results with the indicated variations to the Expected Case:

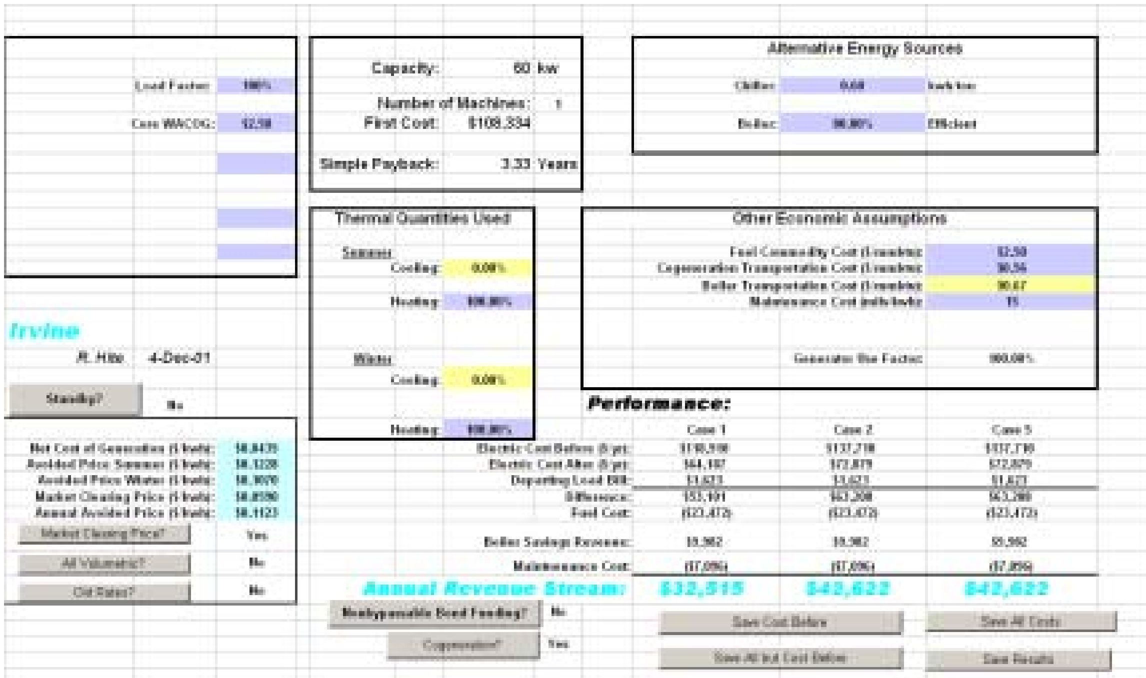
***Table 5. Economic Results*[27]**

Case	Initial Net Positive Annual Cash Flow	Internal Rate of Return	Simple Payback[28]	Average Avoided Cost of Power[29]
For Cases 1-4, the fuel commodity cost is $2.50/mmbtu				
1. Expected Case @ $2.50/mmbtu	$46,600	33.8%	2.5 yrs	13.4 c/kWH
2. If Long Term Rates Were Applied Immediately	$32,500	27.3%	3.3 yrs	11.2 c/kWH
3. If Project Subject to Nonbypassable Bond Servicing Surcharge	$30,800	20.0%	3.5 yrs	10.9 c/kWH
4. Long Term Rates Applied Immediately Along with Nonbypassable Bond Servicing Surcharge	$20,271	13.9%	5.2 yrs	8.7 c/kWH
For all cases following, the fuel commodity cost is $5.00/mmbtu.				
5. Gas Commodity Cost of $5/mmbtu	$31,800	21.2%	3.4 yrs	13.4 c/kWH
6. If Long Term Rates Were Applied Immediately	$21,700	15.2%	5.0 yrs	11.2 c/kWH
7. If Project Subject to Nonbypassable Bond Servicing Surcharge	$20,000	4.0%	5.4 yrs	10.9 c/kWH
8. Long Term Rates Applied Immediately Along with Nonbypassable Bond Servicing Surcharge	$9,900	Neg.	10.9 yrs	8.7 c/kWH

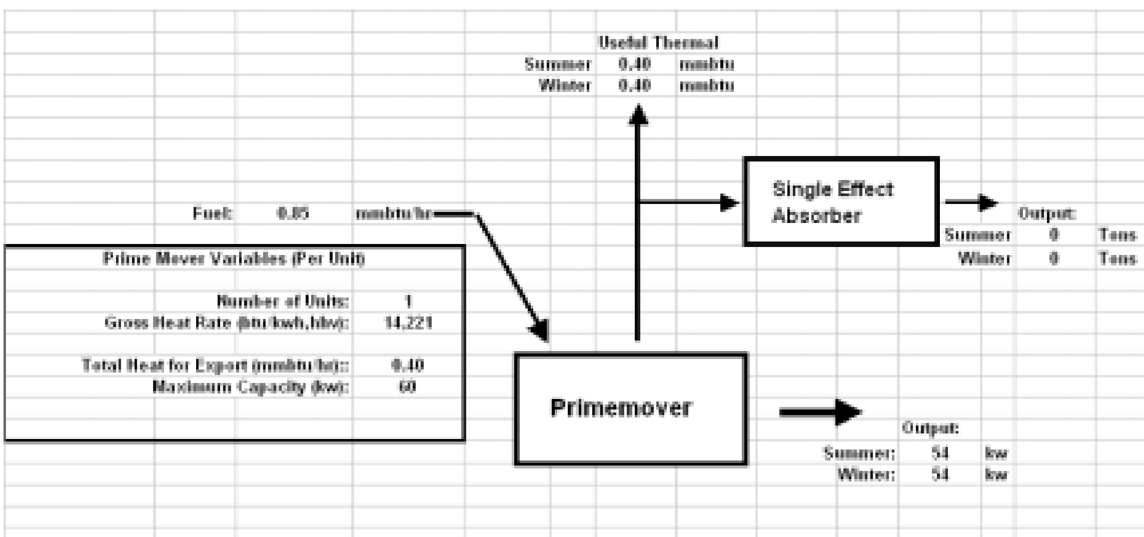
Exhibit 1 - Site Layout



Appendix Sample Calculations (Irvine)



Capacity: 60 kw
Number of Machines: 1
First Cost: $108,334
Simple Payback: 3.33 Years
Alternative Energy Sources
Thermal Quantities Used
Other Economic Assumptions
Irvine
R. Hite 4-Dec-01
Performance:
Case 1
Case 2
Case 3
Annual Revenue Stream:
$32,515
$42,622
$42,622



Useful Thermal
Summer 0.40 mmbtu
Winter 0.40 mmbtu
Fuel: 0.85 mmbtu/hr
Single Effect Absorber
Output:
Summer 0 Tons
Winter 0 Tons
Prime Mover Variables (Per Unit)
Number of Units: 1
Gross Heat Rate (btu/kwh,hhv): 14,221
Total Heat for Export (mmbtu/hr): 0.40
Maximum Capacity (kw): 60
Primemover
Output:
Summer: 54 kw
Winter: 54 kw

Old Load

Southern California Edison
Schedule GS-2: General Service - Demand - Secondary Voltage (delivered and metered at less than 2 kV)

Inputs:	January	February	March	April	May	June	July	August	September	October	November	December	Total
Monthly maximum demand, MMD (kW)	341	343	343	348	286	348	295	336	336	346	358	343	
Monthly electricity consumption (kWh)	68,880	71,280	76,320	68,880	70,800	70,600	75,840	65,280	65,280	79,920	66,400	100,000	879,580
Highest MMD during prior 11 months (kW)	358	358	358	358	358	358	358	358	358	358	358	358	
Billable maximum reactive demand, MRD (kilovars)	0	0	0	0	0	0	0	0	0	0	0	0	
1st Tier	68,880	71,280	76,320	68,880	70,800	70,600	75,840	65,280	65,280	79,920	66,400	100,000	
2nd Tier	0	0	0	0	0	0	0	0	0	0	0	0	
Equivalent Full Load Hours:	202	208	223	198	248	203	257	194	194	231	186	292	
Rate Calculation:													
Customer Charge	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$723.60
Demand Charge - Facility-Related													
$5.40 per kW of MMD, (subject to min.)	$1,841.40	$1,852.20	$1,852.20	$1,879.20	$1,544.40	$1,879.20	$1,593.00	$1,814.40	$1,814.40	$1,868.40	$1,933.20	$1,852.20	$21,724.20
Demand Charge - Time-Related:													
$7.75 per kW of MMD (summer only)	$0.00	$0.00	$0.00	$0.00	$0.00	$2,697.00	$2,286.25	$2,604.00	$2,604.00	$0.00	$0.00	$0.00	$10,191.25
Energy Charge:													
1st Tier	$6,753.98	$6,989.23	$7,483.42	$6,753.98	$6,942.17	$6,942.17	$7,436.35	$6,400.91	$6,400.91	$7,836.41	$6,510.59	$9,813.16	$86,271.12
2nd Tier	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Power Factor Adjustment:													
$0.23/kilovar of MRD if MMD exceeds 200 kW	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sub-Total - $	$8,655.68	$8,901.73	$9,395.82	$8,693.48	$8,546.87	$11,578.67	$11,375.90	$10,879.61	$10,879.61	$9,765.11	$8,512.88	$11,725.66	$118,910.17
- $/kWh	0.1257	0.1249	0.1231	0.1262	0.1207	0.1635	0.1500	0.1667	0.1667	0.1222	0.1280	0.1172	0.1351
													$0.00
Total ($)	$8,655.68	$8,901.73	$9,395.82	$8,693.48	$8,546.87	$11,578.67	$11,375.90	$10,879.61	$10,879.61	$9,765.11	$8,512.88	$11,725.66	$118,910.17
Monthly Average Unit Cost ($/kWh)	$0.1257	$0.1249	$0.1231	$0.1262	$0.1207	$0.1635	$0.1500	$0.1667	$0.1667	$0.1222	$0.1280	$0.1172	$0.1351

Departing Load

Southern California Edison
Schedule GS-2: General Service - Demand - Secondary Voltage (delivered and metered at less than 2 kV)

Inputs:	January	February	March	April	May	June	July	August	September	October	November	December	Total
Monthly maximum demand, MMD (kW)	54	54	54	54	54	54	54	54	54	54	54	54	
Monthly electricity consumption (kWh)	40,176	36,288	40,176	38,880	40,176	38,880	40,176	40,176	38,880	40,176	38,880	40,176	473,040
Highest MMD during prior 11 months (kW)	54	54	54	54	54	54	54	54	54	54	54	54	
Billable maximum reactive demand, MRD (kilovars)	0	0	0	0	0	0	0	0	0	0	0	0	
1st Tier Difference	40,176	36,288	40,176	38,880	40,176	38,880	40,176	40,176	38,880	40,176	38,880	40,176	
2nd Tier Difference	0	0	0	0	0	0	0	0	0	0	0	0	
Rate Calculation:		100.00%											
Customer Charge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Standby Charge:													
$6.77 per kW of stdby	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Demand Charge - Time-Related:													
$7.75 per kW of MMD (summer only)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy Charge:													
	$137.80	$124.47	$137.80	$133.36	$137.80	$133.36	$137.80	$137.80	$133.36	$137.80	$133.36	$137.80	$1,622.50
	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Power Factor Adjustment:													
$0.23/kilovar of MRD if MMD exceeds 200 kW	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sub-Total - $	$137.80	$124.47	$137.80	$133.36	$137.80	$133.36	$137.80	$137.80	$133.36	$137.80	$133.36	$137.80	$1,622.50
													$0.00
Total ($)	$137.80	$124.47	$137.80	$133.36	$137.80	$133.36	$137.80	$137.80	$133.36	$137.80	$133.36	$137.80	$1,622.50
Monthly Average Unit Cost ($/kWh)	$0.0034	$0.0034	$0.0034	$0.0034	$0.0034	$0.0034	$0.0034	$0.0034	$0.0034	$0.0034	$0.0034	$0.0034	$0.0034

New Load

Southern California Edison
Schedule GS-2: General Service - Demand - Secondary Voltage (delivered and metered at less than 2 kV)

Inputs	January	February	March	April	May	June	July	August	September	October	November	December	Total
Monthly maximum demand, MMD (kW)	204	203	203	208	226	288	235	276	276	266	358	341	
Monthly electricity consumption (kWh)	28,784	34,992	36,144	30,080	30,624	31,528	35,664	25,904	26,400	35,744	27,600	58,994	406,880
Highest MMD during prior 11 months (kW)	358	358	358	358	358	358	358	358	358	358	358	358	
Billable maximum reactive demand, MRD (kilovars)	0	0	0	0	0	0	0	0	0	0	0	0	
1st Tier	28,784	34,992	36,144	30,080	30,624	31,528	35,664	25,904	26,400	35,744	27,600	58,994	
2nd Tier	0	0	0	0	0	0	0	0	0	0	0	0	
Rate Calculation:													
Customer Charge	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$60.30	$723.60
Demand Charge - Facility Related		$540.90											
$5.40 per kW of MMD, (subject to min.)	$1,103.40	$1,284.20	$1,204.20	$1,231.20	$896.40	$1,231.20	$946.00	$1,166.40	$1,166.40	$1,220.40	$1,809.20	$1,528.20	$14,596.20
Demand Charge - Time-Related													
$7.75 per kW of MMD (summer only)	$0.00	$0.00	$0.00	$0.00	$0.00	$2,232.00	$1,821.25	$2,139.00	$2,139.00	$0.00	$0.00	$0.00	$8,331.25
Energy Charge													
1st Tier	$2,614.52	$3,431.38	$3,544.03	$2,941.60	$3,002.79	$3,129.86	$3,496.97	$2,461.53	$2,588.60	$3,897.03	$2,706.27	$5,873.70	$39,898.08
2nd Tier	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Power Factor Adjustment:													
$0.23/kilovar of MRD if MMD exceeds 200 kW	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sub-Total - $	$4,098.22	$5,343.58	$4,808.53	$4,233.10	$3,959.48	$6,653.36	$6,323.52	$5,827.23	$5,954.30	$5,177.73	$4,375.77	$7,462.20	$64,187.08
													$0.00
Total ($)	$4,098.22	$5,343.58	$4,808.53	$4,233.10	$3,959.48	$6,653.36	$6,323.52	$5,827.23	$5,954.30	$5,177.73	$4,375.77	$7,462.20	$64,187.08
Monthly Average Unit Cost ($/kWh)	$0.1417	$0.1527	$0.1330	$0.1411	$0.1293	$0.2084	$0.1773	$0.2321	$0.2255	$0.1303	$0.1586	$0.1246	$0.1578

Southern California Edison
Schedule GS-2: General Service - Demand - Secondary Voltage (delivered and metered at at below 2 kV)
Rate Components

Component	Nonbypassable	Non-Gen./ Other	Total			Old Rates Nonbypassable	Non-Gen./ Other	Total		
Customer Charge ($/Mo)	12.24	48.06	60.30			12.24	48.06	60.30		
Demand Charge ($/kw)				Gen Chg	Tot Stby				Gen Chg	Tot Stby
Facilities	2.23	3.17	5.40	1.37	6.77	2.23	3.17	5.40	1.37	6.77
Time Related	0.00	7.75	7.75			0	7.75	7.75		
Energy Charges:										
Summer										
1st Block	0.00343	0.00080	0.11942			0.00372	0.08320	0.08692		
2nd Block	0.00343	0.00080	0.13481			0.00372	0.05019	0.05391		
Winter										
1st Block	0.00343	0.00080	0.11942			0.00372	0.08320	0.08692		
2nd Block	0.00343	0.00080	0.13481			0.00372	0.05019	0.05391		

New Rates

Component	Nonbypassable	Non-Gen./ Other	Total		
Customer Charge ($/Mo)	12.24	48.06	60.30		
Demand Charge ($/kw)				Gen Chg	Tot Stby
Facilities	2.23	3.17	5.40	1.37	6.77
Time-Related	0	7.75	7.75		
Energy Charge ($/kWh)					
Summer					
1st Block	0.00343	0.0008	0.1194200		
2nd Block	0.00343	0.0008	0.1348100		
Winter					
1st Block	0.00343	0.0008	0.1194200		
2nd Block	0.00343	0.0008	0.1348100		

Freeze UnFreeze

		1	2	3	4	5	6	7	8	9	10
IRR 33.82%	$108,334	$42,622	$42,622	$42,622	$32,515	$32,515	$32,515	$32,515	$32,515	$32,515	$32,515

Payback: 2.5

Technical Alternatives And Economic Comparison - Paramount Petroleum

Summary

In 1999 the California Energy Commission chose to investigate the market barriers and implications to widespread implementation of distributed generation. Part of this investigation is this analysis of an industrial class combined heat and power (CHP) facility, both in terms of its physical and economic feasibility as well as challenges it faces through site permitting.

Paramount Petroleum was chosen for this study. They are in the process of installing a 6.5 MW CHP facility to raise steam for their process needs as well as power for their refinery. Combustion turbines were the only technology seriously considered for this application because of the high temperature nature of the thermal needs at the refinery. Other technologies such as micro turbines, reciprocating engines or fuel cells could not raise thermal energy at the temperatures needed on site.

Before Paramount Petroleum narrowed their selection down to a 6.5-MW combustion turbine (the "small" choice), they looked at larger sizes. The intermediate choice was a 25-MW combustion turbine/combined cycle plant. The large choice was a 50-MW (minus) combustion turbine.

The intermediate choice consisted of an aero-derivative combustion turbine that generated power through both a combustion turbine and a steam extraction turbine. The useful heat available for process would come from the intermediate pressure drum of the heat recovery steam generator (HRSG) and the extraction port of the steam extraction turbine. Only 20% or so of the power generated from this facility would be used on site. The balance would have to be sold to another party or on a wholesale market.

The 50-MW CHP plant considered would have heated a variety of refinery processes through the use of heat transfer fluids. Though this type of facility would have been perhaps the most aggressive in terms of energy conservation (the largest energy cascade available at the plant), only 10% of the power generated would have been used on site. In addition, this configuration presented control challenges that made the 50MW option less attractive.

Since this study was initiated, the California Public Utility Commission ended open access so the only real market is with the California Power Authority or with a company who already has a contract with either the California Power Authority or the California Department of Water Resources. Paramount chose the less financially risky option and is building the 6.5 MW CHP facilities only to generate power for their own needs.

This new on site power generation finds itself in an economic environment characterized by the electric tariffs of Southern California Edison Company. The refinery itself is on

an interruptible rate. Curtailments during 2000 and 2001 cost the refinery millions of dollars in penalties as they simply chose not to curtail when required to. They ultimately rented diesel standby units that cost approximately $750,000 per year in rent. They have returned the diesels, confident that their CHP system will keep them from future I-6 penalties. This rental cost is an annual credit that needs to be included with the avoided electricity in order to calculate the economic performance of the new facility. This facility should earn a return on equity of around 30%. Its simple payback before taxes is 2.5 years. This is allowing for the currently high rates to abate somewhat after three years. This is remarkable considering special site challenges that have led to a fairly extraordinary capital cost exceeding $1500/kwh.

A sensitivity analysis was done. The project economics are sensitive to the cost of fuel to the point that with natural gas at $5/mmbtu (double that presumed for the expected case in this study) the economics become marginal. In addition, the impact of non-bypassable surcharges to recover the state's debt for power was considered. There was not one instance where the project remained economically viable were non-bypassable surcharges to become the state's policy.

Site permitting is always an issue for projects of this magnitude and Paramount Petroleum has been no exception. Care needed to be taken that the combustion turbine was not located within 1000 feet of a school or extraordinary noticing requirements would have been required. Emission credits had to be obtained to offset oxides of nitrogen emissions. Very expensive control emission equipment and continuous emission monitoring equipment had to be installed. Aesthetic requirements were imposed by the city of Paramount. A federal Title V application requiring changes in monitoring, record keeping and reporting was required.

This project is to be under construction soon. A partial list of its contribution to the social good (other than its general contribution to the region's economy) is as follows:

Annual Natural Gas Equivalent Energy Savings:	155 million cubic feet
Number of American Homes Served by Energy Savings:	1,900
Number of American Cars Needed Off of Highways to Achieve a Similar Reduction in CO_2 Emissions:	2,400
Number of American Cars Needed Off of Highways to Achieve a Similar Reduction in NO_x Emissions:	14,800

Introduction

In 1999 the California Energy Commission decided to investigate the market barriers and implications to widespread implementation of distributed generation. One of its strategies was to investigate two separate project sites in order to analyze the permitting costs and time requirements for combined heat and power applications. Two sites were chosen. The first is a municipally owned and operated swimming complex and the second is a large asphalt refinery. It was anticipated that these two projects would be different in nature, size and other characteristics and would serve to illustrate the similarities and differences in the permitting process required to make both of them viable.

Site Description

Paramount Petroleum is located in the City of Paramount within Los Angeles County. In the past the refinery processed heavier crude oils to produce a variety of petroleum products. Due to market conditions, it is now primarily an asphalt producing facility.

The refinery was built in the 1930's. The plant capacity is rated at 46,000 barrels per day and it is currently operating at 90% of full capacity. Paramount provides roofing asphalt and paving asphalt to California as well as Oregon, Arizona and Nevada, where it is stored and distributed to those markets, as it is needed.

For several years now, Paramount has been evaluating the feasibility of installing a combined heat and power plant (CHP). The steam requirements have been matched to its electric demand and found to be a reasonably good match. The senior management at Paramount has also expressed interest in several innovative concepts. The first is to match the size of the cogeneration[30] project to the steam load of the facility. This would result in a modest size of 5MW (vs. the 8 MW current peak) for a conventional combined heat and power plant. The second alternative is to match entire thermal load of the refinery, including the high temperature heat applications in the process. This would potentially result in a delivery capability of roughly five times the conventional low temperature application. A CHP plant of approximately 25 MW would be needed to match 600 F process requirements.

The third option that Paramount has considered was to install a large cogeneration plant in order to sell power in the open market. This could be sized up to 50 MW and has significant differences in the way it would be permitted and operated. These three options have been subjected to a preliminary comparative analysis and subjected to a risk assessment by the senior management and owners of Paramount Petroleum. Dana Technologies performed this study and a summary of the results is presented here.

Paramount is an industrial facility with continuous operations which are extremely sensitive to power outages. Shortages of electric power in California has resulted in elevated costs to Paramount since they have opted at times not to disconnect during the requested periods of their interruptible rate arrangement[31]. A three-hour interruption can cost over $100,000. As a result, the refinery rented standby generation at the cost of $500,000 per year. These circumstances have created an even greater sense of urgency related to the ability for Paramount Petroleum to have more control over its electricity supply and costs. This site is of great interest to the Project Team for several reasons. It is willing to consider innovation. Paramount is known for past and current efforts to optimize its energy usage in the form of energy efficiency improvements. There was also obvious interest manifested by senior management in the opportunities and benefits of distributed generation.

Current operations process about 150,000,000 barrels per year. Since it started operations, Paramount has shifted its production from lighter and heavier petroleum products to a majority (65%) in asphalt. The refinery produces several different grades of asphalt that include paving, roofing and treated asphalt. Recent energy efficiency improvements have involved retrofits to the distillation towers, which have resulted in a reduction of 20,000 lbs of steam per tower, or an 11% reduction of steam per unit throughput. Onsite will, under a separate effort, be helping Paramount to identify further opportunities to reduce its energy consumption, while maintaining the same level of production.

Technical Analysis

Energy Consumption Profiles

The average electric load at Paramount is about 5 MW, and in 1999 the average peak was 5.5 MW. The process is carried out 24 hours per day, and the electrical demand is fairly constant. Thermal loads can be segregated between high and low temperature applications. The boilers supply an average of 34,000 lbs/hr of steam at 180 psig[32]. The production of steam represents about 20% of the overall plant thermal requirements of 165 MMBTU/hr. The remainder of the thermal demand is in the form of high temperature loads, mostly in processes which require >600 deg. F heat. The potential thermal loads that could be served by cogeneration thermal energy are listed in Table 6.

Table 6. Refinery Combustion Device Data And Potential Cogeneration Thermal Loads

Combustion Device or Tag No.	Stack Oxygen (%)[3]	Stack Temp. (deg.F.)	Fuel Gas (mscfd)	Calculated Efficiency (%)	Calculated Heat (mmbtu/hr)
Boilers	N/A	N/A	N/A	75[1]	34.2[2]
H-801	6	1200	400	54.1	12.3
H-802	5	940	1050	64.5	39.6
H-805	10	800	250	58.4	08.3
H-860	6	775	150	66.3	05.7
H-601	1.5	785	1200	73.0	51.0
H-602	8	875	400	60.8	13.9
Total					**165.0**

Notes:

1. This is an assumed value and includes de-aerator heating and blow-down losses.
2. Calculated from a net 34,000 pounds/hour-fired boiler output as provided by the refinery.
3. Wet measurement.

The refinery itself supplies part of the fuel. About 38 MMBTU/hr or 23% of the total heating is provided by the refinery, which produces fuel gas and butane off a variety of processes as a byproduct for combustion. Use of these fuels is not recommended for power generation because of anticipated complications of NO_x emission controls. Any added generation capacity would be fueled by natural gas which is currently being supplied by Southern California Gas and which would require modifications and upgrades to the supply system if a large generation facility were to be added to the Paramount site.

Southern California Gas Company distributes natural gas. The distribution network that furnishes gas to the refinery is currently at its maximum capacity and SoCalGas would need to install a new line to supply the cogeneration plant. The size of the new line and the exact interconnection point on their system will depend on the generator selected for the project, its location at the refinery, available delivery pressure and the balance of refinery fuel demand.

SoCalGas has indicated that they have a transmission line just south of the 91 freeways that could be tapped for the large generator or possibly for the intermediate sized generator. The new high-pressure line would be expensive to install but it would reduce or possibly eliminate the need for on-site fuel gas pressure boosting. SoCalGas has, in the past, been willing to access higher-pressure gas if available and at the customers cost. For the customer, the cost of this line would compare to the first cost of a fuel gas compressor and the ongoing cost of compressing the natural gas. A dedicated high-pressure line would be too costly to serve a small generator.

SoCalGas will perform a load study to determine how best to furnish gas to the new cogeneration plant once the generator has been selected by Paramount Petroleum Corporation. For the purpose of this study, it is assumed that gas would be furnished to the small generator at 40 psig and at 400 psig for the intermediate and large generators. Booster compressor power consumption and budgetary cost estimates were based on these assumptions.

Technology Options

There are four different prime movers that come to mind when considering combined heat and power. The most often used is the reciprocating engine. In this particular instance, the application of a reciprocating engine cannot be considered because the reciprocating engine cannot produce the 180-psig steams required by the site. Steam turbines can be used when steam is originally produced at pressures that far exceed the need of the plant. Power is generated then by expanding the steam through the steam turbine to the pressure required by the plant processes. At Paramount Petroleum, steam is raised at the pressure required by the processes.

In larger applications steam can be raised from the exhaust of a combustion turbine by a heat recovery steam generator (HRSG) at pressures and temperatures exceeding those needed by the processes. A steam generator can be used then (as will be discussed below) to reduce the pressure to that needed by the process. The CHP application being considered for the smaller gas turbine is too small, however, to be considered for the use of a steam turbine. Microturbines are too small and the thermal energy they make available for a process is of insufficient quality[33] for the process needs of Paramount Petroleum. Finally, fuel cells are also too small and the thermal energy provided is also of insufficient quality.

Combustion turbines produce high quality thermal energy. They are well suited for a CHP application such as the one being considered by Paramount Petroleum. The three generator sizes addressed in the study were based on the selection philosophy summarized in Table 7. In all cases, the generator prime movers would be combustion turbine engines. General system descriptions based on these three sizes of cogeneration plants are provided in the following subsections.

Table 7. Combustion Turbine Selections

Category	Basis for evaluation	Possible Generators
Small (5-7MW)	Electrical output approximately equal to refinery load.	Solar Taurus 60 Solar Taurus 70 Rolls-Royce 601 KB9
Intermediate (20-25MW)	Medium system cost.	GE LM25OO+
Large (40-49.9MW)	Largest size that is not regulated by the state ENERGY COMMISSION.	GE LM6000 Sprint GE PG6581 B

The combustion turbines would be fitted with heat recovery equipment for cogeneration service. Except for a small amount of radiated heat and lubricating oil heat, all rejected thermal energy from combustion turbines is in the exhaust gases. Exhaust produced by natural gas-fired combustion turbine engines is very clean and of uniform temperature, making it an ideal source of thermal energy. Exhaust temperatures vary from one machine to another and range from about 800 F. to 1050 F.

Combustion turbines are rated in accordance with the specifications issued by the International Standards Organization (ISO). The standard was established to affect a common condition for comparing the performance of turbines from all manufactures around the world. Actual machine performance will vary with site-specific conditions.

Small System

The small cogeneration plant selected for evaluation in this study would consist of a single combustion turbine-generator fitted with a heat recovery steam generator. In this configuration, thermal energy in the exhaust gases would be used to produce refinery process steam. The generator would be connected in parallel with SCE. This cogeneration configuration is the most common type employed by industry and commercial users and there are hundreds of these cogeneration systems in service around the world.

The only non-standard element of this particular cogeneration application would be the pollution control requirement. Combustion emissions must be reduced to very low levels to satisfy SCAQMD requirements. The small cogeneration system would be designed to back out utility power purchases. The electrical control system would be designed to follow the refinery electrical load up to the maximum rated capacity of the generating unit. Most often, the generator in such an application would not produce more power than needed by the refinery. This design basis is a departure from most pre-deregulation combustion turbine based cogeneration systems and is prompted by the costs and complexity of selling surplus generated power today. However, under state law, there still is the possibility of selling power to an adjacent consumer.

Intermediate System

The intermediate sized cogeneration plant performance was based on the General Electric LM2500 turbine-generator set. The GE LM2500 is the most commonly used generator in the intermediate size range and there are many in cogeneration service around the world. This generator is available in two versions; the standard LM2500 and the LM2500+. The LM2500+ generator is a recent upgrade to the standard unit and incorporates a more efficient compressor section and other changes. The advanced design is 4.5% more efficient and has 25% more capacity. The study used the LM2500+ generator for the intermediate generator.

Although the intermediate cogeneration plant would utilize a single factory packaged generator set much like the small cogeneration plant, it would have few other similarities. The primary differences are that the larger energy output would complicate the use of the thermal energy in the refinery, and the generation of surplus power would force the refinery into the wholesale power marketing business. These changes would make this plant more difficult to operate and it would add risk to the investment.

The LM2500+ machine would deliver about 126 MMBtu/hour of usable exhaust energy. This exhaust energy must be used in an economically beneficial way at the refinery in order to justify the investment for this size of generator. This energy stream is three times greater than the amount needed to meet the refineries process steam load. It can be used to make high-pressure steam to drive a steam-turbine generator in a combined cycle arrangement, or it could be used to heat process fluids.

Process heating in refineries and chemical plants by the use of cogeneration thermal energy has been employed in some plants where electric power is scarce and/or expensive such as in Hawaii, Alaska or Europe. On a world scale, they appear to be gaining in popularity as plant owners become more comfortable with the technology. Process heating was not analyzed for the intermediate generator case because in the intermediate cogeneration case, the small amount of thermal energy that would remain after subtracting the process steam would be more economically used in a combined cycle configuration.

An intermediate or large cogeneration plant configured to make steam exclusively with the exhaust energy would be typically equipped with a triple pressure heat recovery steam generator to make turbine quality steam, process steam, and low pressure steam. This design would maximize the use of available cogeneration thermal energy and was assumed for this study. High pressure superheated steam would be generated to feed an extraction steam turbine for added power generation. Typical steam turbine throttle steam conditions for this size of plant would be 900 psi and 825 Fahrenheit and this steam condition was assumed for this study. The optimized throttle steam temperature may be a little lower to minimize superheat in the process steam taken at the extraction point. All high-pressure steam would flow to the steam turbine-generator.

Intermediate pressure steam would be produced to furnish part of the refinery process load. The heat recovery steam generator will not be able to make all of the process steam[34] needed by the refinery and the balance would be extracted from the steam turbine. Additional heat recovery to make low pressure steam would be optional. The low-pressure steam would be used for de-aerator feed water heating and to serve an absorption chiller. The low-pressure steam would be about 27-psi pressure. The absorption chiller would be used to cool the ambient air entering the combustion turbine compressor, thereby enhancing the combustion turbine performance.

Steam being expanded in the extraction steam turbine that is not needed to meet process requirements would be further expanded to a condenser to increase power generation. This design maximizes the value of the exhaust energy and it provides the capability to meet a fluctuating process steam profile. In this example case the steam turbine-generator would produce about 6,100 kW.

The cogeneration plant would consume some of its power to drive auxiliary equipment, and these auxiliary loads must be subtracted from the generated load because only the net power output matters. The auxiliary loads include the gas booster compressor, cooling water pumps, condenser water pumps, cooling tower fans, enclosure ventilation fans, feed water pumps, controls, and lighting. There would be no transformer losses since the generators would produce the power at the distribution voltage. Total auxiliary load has been estimated to be 354 Kw.

The plant would consume about 2,610 therms of gas per hour, and produce 30.2MW of electricity and 34,000 pounds per hour of process steam. Net thermodynamic efficiency would be 60.67 percent. These are nominal values; engineering would be required to optimize the design for the Paramount Refinery.

The combined cycle plant would be very conventional and involve minimal technical risk. However, it would involve some financial risk because with only one-third of the steam going to process, and only one-fifth of the power going to back out purchased power, it would essentially be a power plant with some process steam bleed. The power plant would have to compete with new combined cycle utility grade plants that are in the development process. The new utility plants are 500 MWh or larger, cost about half as much to build and maintain on a $/kW basis.

Large System

The large cogeneration plant was strategically sized to be less than 50 MW to avoid the California Energy Commission permitting process. The large cogeneration case would be like the intermediate case in that it would make considerable surplus power for sale in the deregulated power market. In the case of the larger generators, only about 13 percent of the power would be used in the refinery.

Two generator options were investigated for the large cogeneration plant; the GE LM6000 Sprint and the GE PG6581 B generator sets. The Sprint is an aero-derivative machine that has its origin as the Boeing 747 airplane engines. The PG6581 B turbine-generator is a heavy frame industrial machine that has been manufactured for many years and has become a classic cogeneration generator for paper mills, chemical plants and refineries. Both machines were investigated because they offer a much different combination of power generation performance and heat quality for process heating purposes.

The LM6000 Sprint generator is the most efficient combustion turbine currently available on the market. It incorporates water injection compressor cooling to boost power output and efficiency. This feature results in a higher power output than the conventional simple cycle version but this feature does consume de-mineralized water. The nominal water requirement for inter-cooling purposes is 3.8 gpm.

For the large cogeneration study option, it was assumed that the exhaust energy was used to heat process fluids and to make process steam. Combined-cycle cogeneration thermodynamics for the larger generators would be similar to that described for the intermediate system. The cogeneration scheme consisting of process fluid heating was selected for analysis for the large generators in order to evaluate all potential cogeneration plant design options for the refinery.

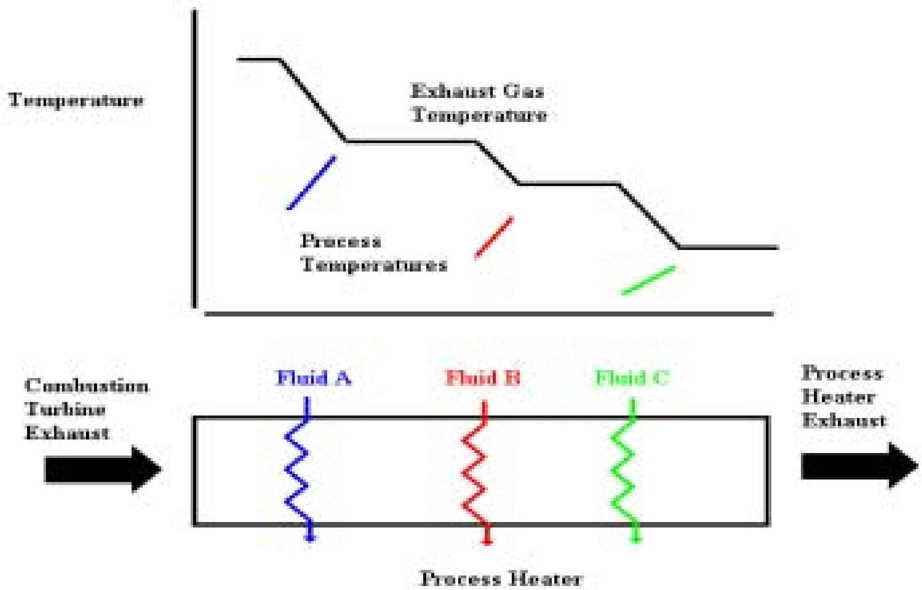
The total refinery thermal load that could potentially be served by cogeneration is 165 million Btu/hour. This includes the process heaters and process boilers. The available thermal energy from the combustion turbines is about 180 million Btu/hour from the LM6000 Sprint machine, and about 245 million Btu/hour from the PG6581 B machine. This is considered to be the potential energy that is available and is based on removing heat from the exhaust gases down to 200 F.

Process Temperature Demands and Complications

Since the plant would sell most of the power in the competitive deregulated power market, it would be important to maximize the use of the available thermal energy to reduce the power generation cost. One of the limiting factors of using this available cogeneration energy at the refinery is the duty temperature of the process fluids. Process heating requirements are, for the most part, concentrated above 600 F requiring a relatively high quality energy source (at temperatures that exceed 600 F).

Cogeneration thermal energy is classified as a medium quality energy source because the available exhaust gas temperature ranges from about 1000 F down to about 200 F. Unlike fuel energy, it cannot be tailored to meet specific thermal requirements. The use of combustion turbine exhaust energy to heat refinery process fluids is not a perfect match. Some low temperature energy in the exhaust gases cannot be recovered for economic gain. These constraints in the use of recovered heat are illustrated in Figure 11.

Figure 11. Theoretical Use of Combustion Turbine Exhaust to Heat Multiple Fluids



A common method of heating process fluids with combustion turbine exhaust gases is to use an intermediate heat transfer fluid. This design works well and there are numerous commercial installations, but the use of the fluids is temperature limited. Energy can only be transferred from a higher temperature source to a lower temperature sink. As the fluid that it is heating cools the exhaust steam, it finally reaches a temperature that is too low for that particular fluid (say Fluid A). There is still heat available to be transferred to a lower temperature fluid (say Fluid B). The process is repeated and the exhaust stream is cooled to the point that it is only useful for heating Fluid C. Finally, the temperature is so low that it must be exhausted (to prevent condensation and thus corrosion in the process heater stack). At this point the exhaust flow is only useful for contributing to the entropy of the universe.

Heat transfer fluids are rated for use up to 700 F, and they will begin to breakdown when operated at the upper temperature range. The heat recovery system design must avoid this phenomenon because it causes some of the fluid to turn to sludge which is a heat transfer fouling problem, a disposal problem, and an operational cost problem. Four of the six process streams at the Paramount Refinery, representing 86% of the process-heating requirement, must be heated in excess of 600 F. Three of these streams must be heated at least 650 F. Only a third of the heat made available in the turbine exhaust exceeds these temperatures. The balance of the heat must be used for other process streams.

Separate heat recovery coils located in the combustion turbine heat recovery device would transfer heat directly to the process streams. The heat recovery coils would be oversized slightly to accommodate flow rate fluctuations in process fluids. Temperature control would be achieved by diverting some of the process fluid stream through coolers that would make process steam. The process temperature control coolers and the waste heat recovery steam generator located in the exhaust gas stream would make about 47,000 pounds per hour of process steam.

Back-Up Provision of Thermal Energy

One of the problems with using a cogeneration plant to heat process fluids is the potential for generator trips and the subsequent loss of exhaust heat. Although combustion turbine based cogeneration plants are very reliable, the fact that the generator is connected into the utility grid makes the plant susceptible to electrical disturbances that can cause the generator to become disconnected from the grid. The generator would be protected from faults and other disturbances that could occur on the 66 kV line into the refinery. Likewise, the SCE line would be protected from faults and disturbances at the cogeneration plant. Sensitive relays in the electrical equipment would provide this protection.

Upon sensing a threatening disturbance, one of these relays will open the generator breaker. When this occurs, the combustion turbine load would disappear, the firing rate would be curtailed and the exhaust gas temperature would drop. These actions would occur in a very short period of time. The control system would be designed to keep the combustion turbine running during such a disturbance, but sometimes a significant fault can cause the combustion turbine to trip as well. The cogeneration system must be designed to accommodate this type of operational upset.

The proposed design approach for solving this type of problem would be to include a duct burner in the turbine exhaust stream that would furnish the heat displaced by the turbine in the event of a generator trip situation. This would be a natural gas-fired burner that would fire up automatically to maintain gas temperature entering the heat recovery system. The heat recovery system would also be equipped with an induced draft fan to replace the gas flow in the event the combustion turbine tripped. This fan would be located between the heat recovery system and the stack.

Sale Of Surplus Power

During the Carter Administration, Federal laws were passed requiring all utilities to interconnect with and buy power from independent generating plants that met Federal standards for efficiency and alternative energy sources. The Federal laws do not allow the independent generators to sell power to retail customers. The Federal law reserves this for the utilities.

The California deregulation laws had set up a free market for power sales and purchases with the utilities serving as distributors. It did not prevent utilities from generating power for sale, but they are restricted from doing so in their own service territory. California consumers could purchase electricity direct from non-utility suppliers called Electric Service Providers. On September 20th, 2001, the California Public Utilities Commission suspended direct access. The refinery would have to negotiate a contract with the

California Power Authority or to an independent trader in order to export power for sale. Edison will not purchase the power at this time.

Electrical Interconnection Issues

The Federal Energy Regulatory Commission (FERC) requires the states to develop and publish electrical interconnection standards for the benefit of promoting open access to the utility grid system for qualified cogenerators and independent power producers. The California Public Utility Commission is charged with the duty of executing the Federal Order, and it in turn directed each state chartered public utility to develop the standards that it proposed to use for its service territory. The approved standards were issued by the utilities in compliance with Federal and State laws.

The serving utility for the Paramount Refinery is the Southern California Edison Company (SCE). The minimum design, operation and maintenance requirements for the parallel interconnection of generators in the SCE territory are specified in a document called "Operation, Metering, and Protection Relaying" issued by SCE in March 1994. The refinery is served by one 66 kV line that runs along Downey Boulevard. This line is called the center-Imperial line and interconnects two substations that are only a few miles apart. The refinery supply tap is immediately in front of the refinery main office, and it runs into the refinery to a SCE owned substation, called DOUGOIL substation. A request was made to SCE to examine the potential system changes needed to interconnect with three sizes of generators being considered at the refinery. Upon receiving this request, SCE performed a preliminary evaluation of their system to determine potential issues with the three generator sizes under investigation.

The SCE fast study review results are:

- Existing SCE 66 kV tap circuit conductors appear to be sufficiently large for the three cases being studied.

- SCE will require that the customer pay for the installation of a 66kV circuit breaker to replace the existing 66 kV fuse at the DUGOIL substation.

- Customer should note that the existing DOUGOIL 66kV: 12kV transformer is rated 11.2/14MVA OA/FA. It would have to be replaced for the larger generator cases at customer's expense.

- The existing DOUGOIL 35 ft X 55 ft fenced area may not be sufficient to allow the installation of the 66kV circuit breaker. If existing area is insufficient, customer would have to provide additional dedicated land for the equipment at either the existing substation site or an alternate location.

- SCE will require the customer to install adequate protection for the relaying and related equipment. The scope of this effort will be determined by the detailed “Method of Service” study.

- The existing low side (12nkV) protection will require further review. SCE may require the installation of additional circuit breaker(s). The scope for this is to be determined by the detailed Method of Service Study.

These preliminary results were expected except for the requirement to install a 66 kV switch for all of the generator cases under investigation. This was not expected for the small generator. A 66 kV switch is a very expensive because of the voltage rating. SCE estimated the cost at $500,000.

In the case of the intermediate and large generators, there is no question that a new 66kV switch would be needed. In those cases, a completely new substation would be required because none of the existing electrical equipment has sufficient current rating to accommodate the power these generators would deliver. But in the case of the small generator engineering was performed to examine this issue and a proposed interconnection design was developed that would not utilize a new 66kV switch.

SCE must be contracted to perform a method of service for interconnecting with cogenerators. This is a study performed by SCE at Paramount's expense and would address all relevant technical, safety, and commercial issues associated with the parallel interconnection and transmission of power from the selected generator. The price of this study would depend on the size of the generator, and its intended service. If the decision is made to install a cogeneration plant, then Paramount must hire SCE to engineer the changes to their electrical supply system. This effort would also define the price to make the construction changes.

Environmental Considerations

The Paramount Refinery is classified as a RECLAIM facility by the SCAQMD, which means it is subject to the rules of that program for NO_x and SO_x air pollution limits. The refinery has a RECLAIM permit for the discharge of NO_x and SO_x pollutants. The RECLAIM program provides the freedom for the refinery to buy or sell emissions into the emissions market to meet the annual limits.

A new emission source can be added to a RECLAIM facility, but the facility permit limits cannot change. Therefore, the addition of the cogeneration plant to the refinery will affect the balance of emissions that can be contributed to the facility permit limits by other sources within the refinery. Displaced emissions from central station utility plants cannot be factored into the analysis. If another unrelated company owns the cogeneration plant, the cogeneration plant emissions would not affect the refinery RECLAIM balance.

The small and intermediate sized cogeneration plants described in this study would back out process steam produced by the existing boilers and actually reduce facility emissions. The large cogeneration plant designs that perform process-heating functions would also reduce NO_x emissions. This would ultimately depend on the specific heaters that were taken out of service by the larger generators.

Typical Capital Costs

Project capital cost estimates were developed using historical cost data and vendor prices for the primary equipment when available. A rigorous pricing effort could not be performed because it would require a significant engineering effort. Prices were obtained for the generators and one heat recovery device bid was obtained. Other line items were estimated using historical data. The capital cost data are summarized in Table 8.

Financial Calculations[35]

Financial calculations were prepared by Dana Technologies to predict the financial performance of the three sizes of cogeneration plants. For the large generator case, calculations were prepared for both the GE LM6000 Sprint machine and the GE FR6581B machine. The analysis was to satisfy these objectives:

- To provide a basis to compare the three plant sizes.
- To function as a working model to evaluate plant design changes.
- To allow project variables to be characterized.

The model cash flow period is ten years. This operating period is sufficient to characterize the effect of energy prices and operational factors on each of the cogeneration plant options. At this time energy prices are difficult to forecast for even a very short period of time and any projection beyond ten years would be meaningless. However, this time frame should not be confused with the useful plant life, which is at least thirty years. The summary of Dana Technologies' analysis is presented in Table 9.

Table 8. Typical Cogeneration Plant Capital Cost Data

($000)

	Taurus 60	LM2500+	LM6000S	PG6518B
1. EQUIPMENT				
Gas TG set	2,060	10,500	13,500	11,500
Heat Recovery System	750	1,900	4,600	4,800
Gas Compressor	300	200	250	300
Steam TG set	0	2,000	800	1,400
CEMS	120	120	120	120
Gen. switch gear	250	400	600	600
Utility substation	100	700	1,200	1,200
Other Electrical	100	200	300	300
Controls	400	900	1,500	1,500
Process equip.	0	0	400	400
Misc. aux. Equip.	200	400	500	500
2. CONSTRUCTION				
SCE	80	300	300	300
Cogen plant	900	2,200	5,000	5,500
3. OTHER				
Shipping & lifting	80	250	320	400
Taxes	370	1,500	2,000	1,800
Engineering	550	1,200	2,000	2,100
Permitting	80	150	200	200
4. TOTAL	**6,340**	**22,920**	**33,590**	**32,920**

Table 9. Financial Analysis Summary

	Taurus 60 (Small)	**LM2500+ (Intermediate)**	**LM6000 (Large)**	**PG6518B (Large)**
Est. Capital Cost (mil$)	6.34	20	30	27
Project Income (mil$/yr)				
Power to refinery	3.12	03.20	03.20	03.20
Exported power	0.00	13.78	21.57	17.75
Heat to refinery	1.67	02.06	07.46	10.31
Subtotal incomes	4.79	19.04	32.23	31.26
Project Expenses (mil$/yr)				
Fuel	2.87	11.43	19.39	20.11
Maintenance	0.27	01.02	01.41	01.18
Operations	0.15	00.45	00.45	00.45
Other misc.	0.20	00.28	00.28	00.28
Subtotal expenses	3.49	13.20	21.54	21.95
Operating Profit (mil$/yr)	1.30	5.85	10.69	9.32

Notes:

(1) Combustion turbine operates 95% of the year, 8,322 hours.
(2) Electrical and thermal loads are relatively steady.
(3) All fuel is natural gas costing $0.50/therm.
(4) Refinery power is valued at $O.O7[36]/kW-hr., export power is $O.O55[37]/kw-hr.
(5) A high-pressure gas line is installed to serve the medium and large cogen plants.
(6) Refinery electric load is 5.5MW.
(7) Operating profits are not discounted.

Preliminary Conclusions

The results of this study are condensed into a single table that shows a qualitative risk assessment offered by Dana Technologies. The risk assessment is presented in terms of grades "A " being most desirable.

The risk grades are intended to serve as a means to compare the cogeneration plants that were investigated, and not intended to serve as an absolute gauge for cogeneration versus no cogeneration. Also, technical risks that were assigned grades lower than "A" does not imply that those plants will not work; it means that there is a greater likelihood that there would be start-up and operational problems. The type and magnitude of these problems cannot be assessed qualitatively without significant engineering effort.

Table 10. Summary Of Cogeneration Options For The Paramount Petroleum Corp. Refinery

Plant Parameter	**Taurus 60 (Small)**	**LM2500+ (Intermediate)**	**LM60005 (Large)**	**PG6518B (Large)**
Est. Cap Cost (Mil$)	6.3	22.9	33.5	32.3
Capacity (kw)	5,250	33,050	48,570	40,950
Cost Factor ($/kw)	1,200	692	690	790
Efficiency (%)	77.3	60.6	67.3	70.8
Power Gen Cost ($/kw-hr)	0.0389	0.03725	0.0324	0.0320
NO_x Emissions (Ibs/hr net)	-1.7	-.05	-.48	-7.9
Technical Risk	A	A	C	C-
Cost Overrun Risk	A	B	C	C
Financial Risk	A	B-	B-	C
Potential Financial Reward	C	C	A	A-

Note: A grade = most desirable

The refinery has a modest steam load that could be served by either the small or intermediate cogeneration plants with minimal risk. The small cogeneration plant is the most expensive to build and operate in terms of the cost per unit of capacity; but it does not rely on revenues from power sales, and so avoids all of the complexity and costs associated with selling wholesale power. It would also provide a very valuable function as an uninterruptible power supply to the refinery.

The intermediate-sized cogeneration plant does involve some financial risk because it must rely on power sales to recover the capital cost, and the value of this surplus power is difficult to assess at this time. This study does indicate that the power generation cost is fairly high compared to large combined cycle plants that dominate the new power plant market. This could be a problem if many of these plants come on-line in future years. If the intermediate-sized plant is seriously considered, a more rigorous financial analysis is recommended to verify that the plant would be a long-term financial success. In addition, Paramount Petroleum, should it pursue this or the larger system, may consider it useful to work with an energy trading or risk management firm cost effectively trade the power in an open market.

The large cogeneration plants would back out gas use in the refinery heaters creating a significant value. However, because of the high process fluid temperatures and the number of individual process streams involved, the cogeneration plant and auxiliary systems would be complicated. This technical complexity and the complexities associated with selling wholesale power mean that the large cogeneration plant would be a major undertaking for the refinery. The potential for significant diversion of refinery resources from the core business of being a first-rate asphalt producer should be given full consideration.

It appears that all the options evaluated present similar marginal costs of generation. What will ultimately define the selection criteria will be the relative risk associated with the investment. A smaller plant will yield a smaller return, but also is of lower operational and cost risk to the plant. A larger plant presents the additional complications of process interface (and its attending cost risks in terms of lost production) and operational difficulty if wheeling power. However, the returns are significant (shorter paybacks) and could represent a sizable opportunity for investment at this site if the current high prices for electricity are sustained in the State.

Life Cycle Economic Analysis of the Project to Be Constructed

Further economic analysis has been done that captures significantly more rigor regarding the likely price of energy and the impact of debt and taxes on the project. As Paramount Petroleum has chosen to move ahead with the smaller combustion turbine, this further analysis was performed with this machine in mind.

The electric rate that applies for this project is I-6 (transmission). This means that the facility is under an interruptible rate but is served at voltages that qualify it for a somewhat lower rate than if it were metered off utility's transmission service. As an interruptible customer, Paramount Petroleum has chosen to operate during interruptions. As a result, the refinery has paid several millions of dollars worth of penalties. This project would allow Paramount Petroleum to remain on I-6 primary and avoid the penalties. Or instead, they could have installed diesel generators and accomplished the same task. Or as another choice, they could have opted out of I-6 to be served under TOU-8 (transmission). In this third choice, the rate is more expensive but they are not curtailed and have no requirement to install any generation.

Two of the scenarios analyzed test the installation of a CHP project instead of installing diesel generators or going to a more expensive rate. The third scenario investigates the economics of a project such as Paramount Petroleum's where the customer is originally on TOU-8 (transmission)[38]. The fourth scenario is that the CHP plant will be tested against the alternative of not curtailing and therefore paying penalties under I-6. The CHP system will not be tested against a customer who would otherwise remain on I-6 (transmission) and continue to take power even though they were curtailed. Were the customer to do this, the penalties would add up to $54 million per year. This is clearly a choice inferior to either renting diesels for standby at a pre-tax $750,000 per year or operating on TOU-8 (transmission) with a pre-tax retail electric cost penalty of about $1.1 million per year.

The Price of Natural Gas

Anomalous conditions existed prior to this winter that lead to some fairly drastic price excursions for the price of natural gas in California. There are a number of explanations for this but a general consensus is emerging that the basis at the Arizona border that led to these prices was, in and of itself, anomalous. For the purposes of this study, SoCalGas' forecasted weighted average cost of gas (WACOG[39]) in the 2000 California

Gas Report would be used as a proxy commodity cost of gas in California. This forecasted border price averages around $2.50/mmbtu. A second case will assume that it doubles to $5.00/mmbtu/hr for the period in question (10 years). For the fuel that is avoided in the existing boilers, the SoCalGas transportation tariff presumed will be GT-F3. For the prime mover fuel, the tariff will be GT-F5.

The Price of Electricity

A number of things have worked together to stabilize the price of electricity. Unfortunately, most of these factors have worked to keep the price high. On June 1, 2001, the California Public Utility Commission was forced to raise electric rates for most of the customers of the state's investor-owned utilities. Though residential rates were increased significantly, commercial and industrial rates were increased even more. Figure 12 illustrates the effect on SCE's avoidable rate[40] of the June 1st rate increased.

For the purposes of this study, these higher rates will be assumed to remain in effect for three years. However, its Onsite's opinion that these rates overstate the real cost of electricity. The real commodity cost of electricity will be driven by the average wholesale price of energy over the period in question plus a surcharge that must be collected to retire debt incurred for power already purchased. Also included would be the cost of uplift charges[41]. The weighted average cost of electricity purchased by the California Department of Water Resources serves as an excellent proxy for the long-term wholesale cost of energy. Using summary data obtained from the State Controller's website, Figure 13 illustrates these average weighted prices for each year in question.

Figure 12. SCE Avoidable Rates[42]

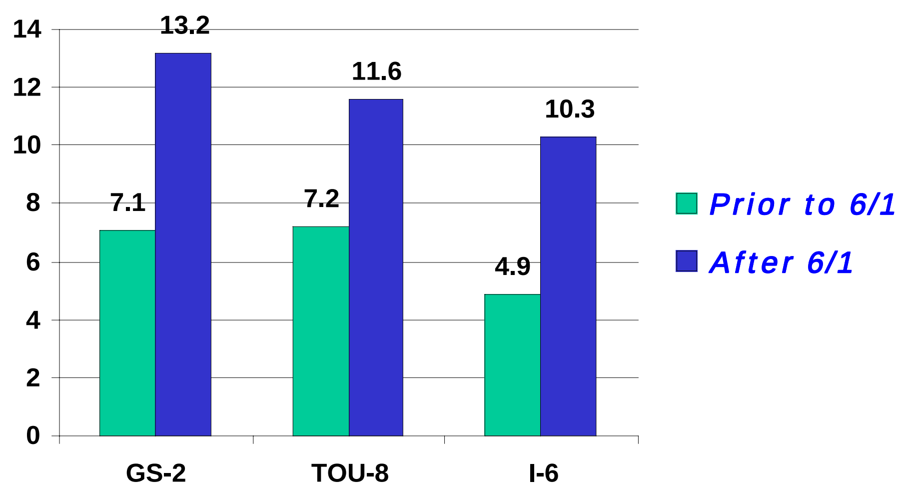
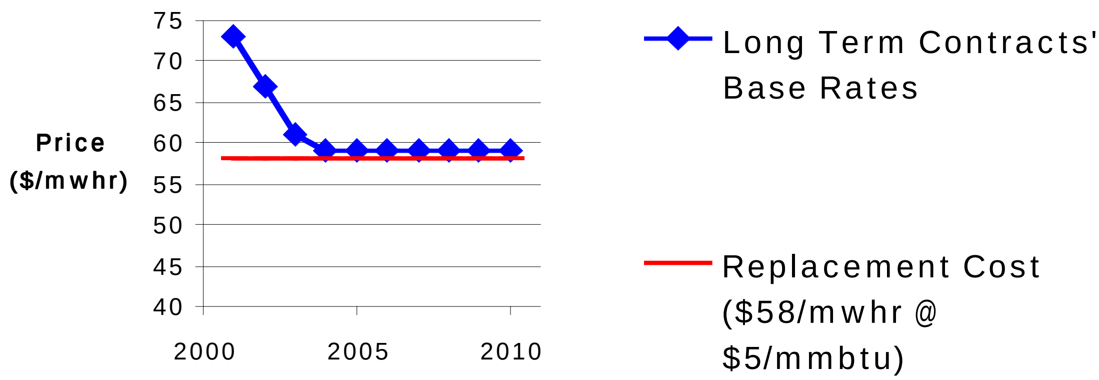


Figure 13. The Weighted Average Cost of Long Term Power



It can be seen that this weighted average cost of energy is $59/MWhr. Indicated also on Figure 13 is the replacement cost of power assuming $5/mmbtu natural gas. This is the cost of capitalizing and fueling a new combined cycle power plant with $5/mmbtu natural gas. Interestingly, the weighted average cost of electricity in the long-term contracts converges on this price. It would seem that there are others who believe that the long-term price of natural gas will be $5/mmbtu[43]. With regard to the surcharge, it appears certain that only the commercial and industrial customers will pay this surcharge. Table 11 illustrates how this surcharge was estimated.

Table 11. The Surcharge Necessary To Service The Bonds

	Amount	Interest	Time to Maturity	Annual Annuity
State Bond	$13,500,000,000	8.00%	15	$1,577,198,857
Utility Bond	$3,500,000,000	11.00%	15	$486,728,338
			Total:	$2,063,927,195

		State Surcharge	Utility Surcharge	Total Surcharge
1988 kwh Volume:	77,367,591,412	0.02039	0.00629	0.02668
1988 kwh Volume plus 7%:	82,783,322,811	0.01905	0.00588	**0.02493**

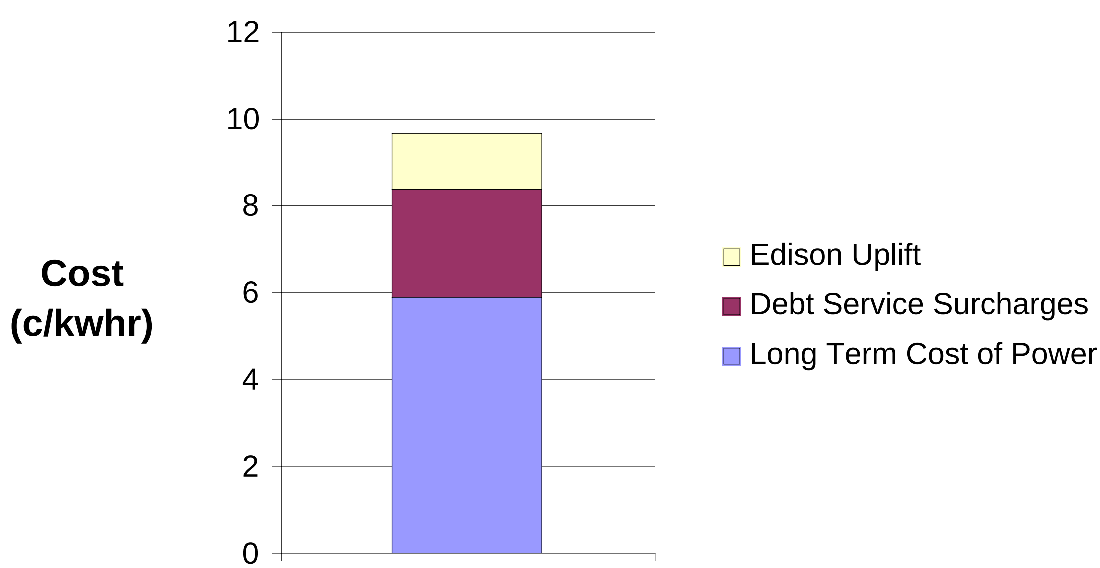
The loads uses in the above table are the loads of all of the customers of all the investor owned utilities with demands exceeding 20 kw for 1988. Assuming a 7% growth in load to the present, it can be seen that a surcharge of 2.5 c/kWH will need to be collected to service the debt. To convert the long-term weighted average cost of electricity plus the surcharge necessary to retire past power purchasing debt, one must account for the utility's cost of uplift (line loss, settlement costs etc). A data point is available from Southern California Edison for the spring of 2000. In July of that year they filed for post transition rates with an average cost of energy that exceeded the PX's average price for the same period by 22%. This then will be presumed as the utility's cost of uplift. Figure 14 illustrates Onsite's estimate of the long-term retail rate for the period in question.

Rate[44]

I-6 is an interruptible time of use rate that Paramount Petroleum pays for power. The average cost of retail energy above must be split into retail energy rates for five different times of use. This is accomplished by "force fitting" the above average retail rate to reflect the relationship between the current energy rates for the five tiers adjusted for the class average load in each of the tiers. Table 12 presents Onsite's forecast for the energy rates.

There is an issue with the surcharge necessary to service the debt incurred as a result of the power purchased previously. It will be the investor owned utilities' contention that this surcharge should be collected on a non-bypassable[45] basis. In fact, the Assembly passed a bill[46] calling for this surcharge to be non-bypassable for all but 250 MW of new onsite generation being added each year. If this surcharge is not bypassable[47], it will have a significantly negative impact on the project being discussed here. That impact will be measured in this analysis.

Figure 14. The Aggregate Long Term[48] Average Retail Energy



Project Description

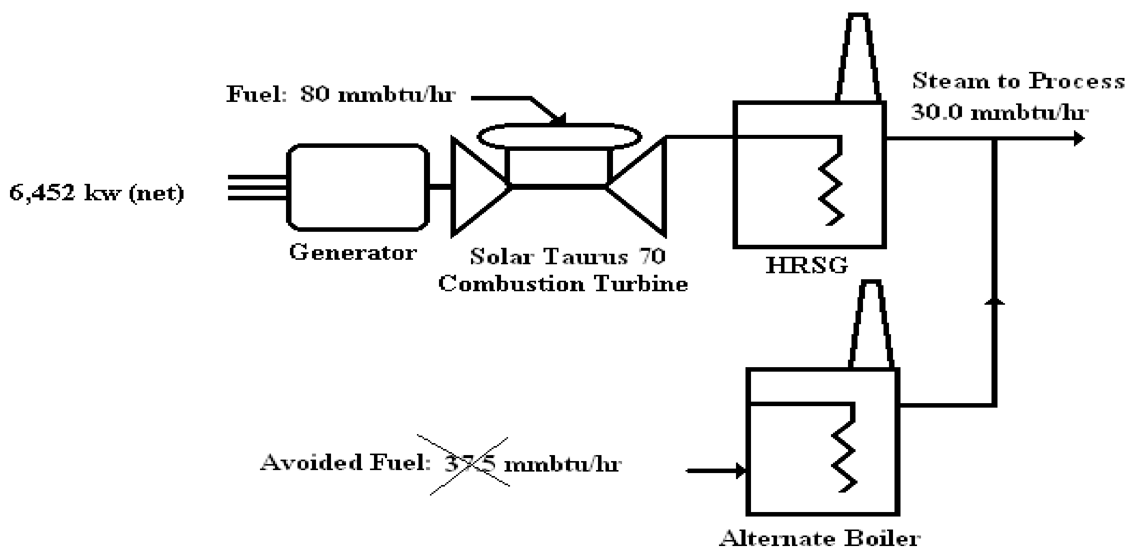
The project envisioned for Paramount Petroleum includes a Taurus 70 combustion turbine and a heat recovery steam generator and is depicted in Figure 15. The Solar Taurus 70 combustion turbine generates 6,452 kW of power and around 30

MMBtu/hour of process steam. Paramount Petroleum fuels the turbine with 80 MMBtu/hour of natural gas but avoids the purchase of 37.5 MMBtu/hour of boiler fuel.

Table 12. Forecasted Edison I-6 (Transmission) Rate (C/Kwh)

	2001 - 2003	**2004-2010**
Summer On-Peak	17.1	15.4
Summer Mid-Peak	9.4	7.1
Summer Off-Peak	8.2	6.2
Winter Mid-Peak	10.3	7.8
Winter Off-Peak	8.2	6.3

Figure 15. The Cogeneration System



Capital Estimate

The capital estimate of the project is presented in Table 13.

Table 13. Capital Cost Estimates

Item	Estimated Cost
Generator Package (Taurus 70)	$2,650,000
HRSG + SCR	$1,000,000
Fuel Gas Compressor	$700,000
Grid Interconnection	$450,000
CEMS	$400,000
Controls	$400,000
Other Auxiliary Equipment	$200,000
Installation	$1,200,000
Engineering	$500,000
Permitting	$50,000
Site Preparation	$1,000,000
Shipping and Lifting	$80,000
Taxes:	$377,000
Contingency	$474,000
Total:	**$9,481,000**

Life Cycle Evaluation

The cost of energy was discussed above. The following assumptions will be used for the Expected Case:

Table 14. Economic Assumptions For Expected Case

Assumption	Value
Installed Cost	$9,481,000
Commodity Rate for Fuel ($/mmbtu):	$2.50
Other wise Applicable Transportation Tariff:	SoCalGas GTF-3
Cogeneration Gas Transportation Tariff:	SoCalGas GTF-5
Current Electric Rate Tariff:	Edison I-6 (transmission)
Period for Current Tariff:	First 3 Years
Long Term Wholesale Price of Power ($/MWh):	$59
Marginal Maintenance ($/MWh):	$6
Fixed Annual Maintenance:	$350,000
Diesel Annual Standby Rental	$750,000
Debt Interest:	6%
Debt/Equity Ratio	50%
Income Tax Rate:	42%
Ad Val Orem:	1.5%
Depreciation:	10 Year, Straight Line

In the first scenario, the alternatives tested assume that Paramount Petroleum remains on I-6 (transmission). The first alternative assumes that the customer rents 5 MW of diesel standby capacity to avoid curtailment at a recurring cost of $750,000 per year. Table 15 is a compendium of results with the indicated variations to the Expected Case for this scenario:

Table 15. Economic Results CHP Tested Against Diesel Standby Alternative

Case	**Initial After Tax Net Positive Annual Cash Flow**	**Internal Rate of Return[49]**	**Simple Payback[50]**	**Average Avoided Cost of Power**
For Cases 1-4, the fuel commodity cost is $2.50/mmbtu				
1. Expected Case @ $2.50/mmbtu	$1.98 Million	31.7%	2.5 yrs	9.4 c/kWH
2. If Long Term Rates Were Applied Immediately	$1.40 Million	23.7%	3.4 yrs	7.3 c/kWH
3. If Project Subject to Non-bypassable Bond Servicing Charge	$1.29 Million	12.4%	4.1 yrs	6.9 c/kWH
4. Long Term Rates Applied Immediately Along with Nonbypassable Bond Servicing Surcharge	$702,000	5.0%	6.0 yrs	4.8 c/kWH
For all cases following, the fuel commodity cost is $5.00/mmbtu.				
5. Expected Case @ $5.00 /MMBtu	$1.52 Million	19.7%	3.3 yrs	9.4 c/kWH
6. If Long Term Rates Were Applied Immediately	$942,000	12.1%	4.8 yrs	7.3 c/kWH
7. If Project Subject to Nonbypassable Bond Servicing Surcharge	$829,000	Neg.	8.3yrs	6.9 c/kWH
8. Long Term Rates Applied Immediately Along with Nonbypassable Bond Servicing Surcharge	$245,000	Neg.	12.1 yrs	4.8 c/kWH

In the next scenario (Table 16), the customer is presumed to have "opted out" of I-6 for TOU-8 except that he installed the CHP system. The analysis is performed by calculating the customer's bill without CHP at the TOU-8 (transmission) rate and calculating the departing load costs (standby and non-bypassables) at the I-6 (transmission) rate.

Table 16. Economic Results CHP Tested Against A Switch To Tou-8 (Transmission)

Case	Initial After Tax Net Positive Annual Cash Flow	Internal Rate of Return[51]	Simple Payback[52]	Average Avoided Cost of Power
For Cases 1-4, the fuel commodity cost is $2.50/mmbtu				
1. Expected Case @ $2.50/mmbtu	$1.85Million	26.4%	2.7 yrs	10.5 c/kWH
2. If Long Term Rates Were Applied Immediately	$1.1 Million	16.2 %	4.2 yrs	7.8 c/kWH
3. If Project Subject to Nonbypassable Bond Servicing Surcharge	$1.1 Million	3.3%	5.3 yrs	8.0 c/kWH
4. Long Term Rates Applied Immediately Along with Nonbypassable Bond Servicing Surcharge	$399,000	Neg.	9.0 yrs	5.3 c/kWH
For all cases following, the fuel commodity cost is $5.00/mmbtu.				
5. Expected Case	$1.4 Million	12.7%	3.8 yrs	10.5 c/kWH
6. If Long Term Rates Were Applied Immediately	$640,000	2.9%	6.5 yrs	7.8 c/kWH
7. If Project Subject to Nonbypassable Bond Servicing Surcharge	$693,000	Neg.	21.4 yrs	8.0 c/kWH
8. Long Term Rates Applied Immediately Along with Nonbypassable Bond Servicing Surcharge	($57.2)	Neg.	36.3 yrs	5.3 c/kWH

In the third scenario (Table 17), the customer is presumed to be on TOU-8 (transmission) and changing to I-6 is not an option. In the last scenario assesses the customer's actual choice. The customer remains on I-6 (transmission) and simply avoids paying penalties. The penalties will be assumed for the full 150 hours curtailment allowed under the rate schedule.

Table 17. Economic Results CHP Tested Purely Under TOU-8 (Transmission)

Case	**Initial After Tax Net Positive Annual Cash Flow**	**Internal Rate of Return**[53]	**Simple Payback**[54]	**Average Avoided Cost of Power**
For Cases 1-4, the fuel commodity cost is $2.50/mmbtu				
1. Expected Case @ $2.50/mmbtu	$1.9 Million	26.6%	2.7 yrs	10.5 c/kWH
2. If Long Term Rates Were Applied Immediately	$1.1 Million	16.4%	4.2 yrs	7.8 c/kWH
3. If Project Subject to Nonbypassable Bond Servicing Surcharge	$1.2 Million	3.5%	5.3 yrs	8.0 c/kWH
4. Long Term Rates Applied Immediately Along with Nonbypassable Bond Servicing Surcharge	$405,000	Neg.	9.0 yrs	5.3 c/kWH
For all cases following, the fuel commodity cost is $5.00/mmbtu.				
5. Expected Case	$1.4 Million	12.9%	3.8 yrs	10.5 c/kWH
6. If Long Term Rates Were Applied Immediately	$645,000	3.1%	6.4 yrs	7.8 c/kWH
7. If Project Subject to Nonbypassable Bond Servicing Surcharge	$698,000	Neg.	20.7 yrs	8.0 c/kWH
8. Long Term Rates Applied Immediately Along with Nonbypassable Bond Servicing Surcharge	($52,000)	Neg.	35.0 yrs	5.3 c/kWH

Discussion

There are several things that can be observed from the "Life Cycle Evaluation". Each will be discussed here:

For the Instant Project, the Economics Look Exceptional

Paramount Petroleum should be served well by this investment. They have avoided the need to rent diesel standby and the necessity of "opting" out to TOU-8 (transmission). This means that their return on equity after taxes should exceed 25%. Paramount Petroleum is half an energy business and half a construction materials provider. In the first instance, the average return on equity is 24%. For the construction materials business the average return on equity is 9.6%. So by either measure, this should be an attractive investment compared to those industries are used to making[55].

For the Time Being, the Purely Economic Play Seems Viable

Not every scenario will have the opportunity of being on an I-6 rate structure. Table 17 demonstrates the impact on the average TOU-8 (transmission) customer who would be installing the CHP plant as a pure economic play. If the installation is soon, the customer can expect a return on equity of almost 27%. This still remains attractive. This is particularly encouraging given the relatively high capital cost associated with this particular plant. However, if the electric rates fall as they are anticipated to do, projects with this sort of capital burden may become marginal.

Certain Sources of Value Made Significant Contributions

Table 15 demonstrates that if there is something to add to the already present values, the economics for this project become more robust. In the first scenario, avoiding the rental of diesel standby, over 5 points were added to the IRR. It seems that the economics were indistinguishable between whether the customer was on TOU-8 (transmission) in the first place (Table 17) or avoided it through the installation of CHP (Table 16).

The Window of Opportunity

The electric rates are high. They are higher than they should be and therefore they can be expected to go down. Onsite believes that the long-term rates to industrial customers will track the long-term contracts signed by the California Department of Water Resources. These contracts will arrest the fall of the electric rates possibly as soon as in the fourth year. Still, for this project, were it not for this window of opportunity (the three years of extraordinarily high rates), Table 17 (Case 2) tells us that the IRR would really be around 16%. As a result, this project would not contend as well as other investment opportunities available to the refinery. CHP for customers such as these can earn extraordinary revenues if they are installed quickly. They may even earn back their construction costs before the rates go down. However, after that the opportunity may not be as attractive.

CHP Could Be Sensitive to the Price of Fuel

In the expected case (Table 17), CHP is very sensitive to the price of natural gas. If the fuel is assumed to cost $5/mmbtu, the rate of return falls to less than 13% (see Table 17, Case 5). In the period after electric rates fall, there is almost no IRR to be earned. Once again, this customer's capital costs are high and Edison among the lowest offers the electric rate. Still, those expecting full mitigation on the thermal side (as the fuel costs for simply raising steam are high as well) will be disappointed. The economics of these projects are sensitive to fuel costs.

Nonbypassable Surcharges to Service the Debt Will Be Devastating

Were this customer to know the cost per kWh of servicing the debt for past purchases of electricity and were he to be convinced that these costs would be nonbypassable, this project would probably never be built. An inescapable conclusion to be reached once the results of this analysis are digested is that the imposition of nonbypassable surcharges to service the state's power debt will end the development of CHP in service territories of the investor owned utilities in the state of California by informed investors.

Permitting Process

The environmental approval process for siting and permitting of a distributed generation (DG) source involves multiple agencies with varying objectives. For all DG projects, construction and operating approvals must be obtained from local jurisdictions. The more involved approval procedures are those required by the local planning and building departments and the air district. Local planning and building departments must ensure that a DG project complies with local ordinances (e.g., noise, aesthetics, set-backs, general plan and zoning, land use), and standards and codes (e.g., fire safety, piping, electrical, structural, etc.). Approvals may be in the form of a permit or license issued after an agency has verified conformance with requirements, or in the form of a program (e.g., landscaping, noise monitoring) that must be developed to ensure the environmental impacts are mitigated. The number of approvals will vary depending on project characteristics such as the size and complexity of a project, geographic location, the extent of other infrastructure modifications (e.g., gas pipeline, distribution system, sewer connections), and potential environmental impacts of construction and operations.

For an existing industrial facility, such as Paramount Petroleum (Paramount), the addition of a new turbine requires modifying any existing facility-wide approvals, as well as undergoing review for the individual piece(s) of equipment and its incremental additional environmental impacts. Paramount has a facility-wide air permit (Title V) issued by the local air district, the South Coast Air Quality Management District (SCAQMD). Additionally, Paramount has a conditional use permit (CUP), issued in the mid-1990s as a result of its development of reformulated gasoline. To address agency approval requirements, Paramount continues to maintain its established and proactive working relationships with the approval agencies, as well as the community members. This includes discussions with agencies prior to submitting the needed information for agency review in order to address potential regulatory barriers and understand current requirements. Furthermore, in addition to Paramount's in-house staff and management, consulting support has been sought for air quality and environmental assessment issues.

Given the proposed turbine addition, an air permit to construct and operate the turbine is needed, and the Title V permit must be amended to include the turbine. Paramount will be meeting the SCAQMD best available control technology standards through the use of selective catalytic reduction (for oxides of nitrogen), ammonia degradation catalyst[56] and a CO oxidation catalyst. With regards to the CUP, the City of Paramount (City) has requested that previously agreed upon CUP conditions be implemented and updated, accordingly. A negative declaration is expected for the turbine addition.

The aforementioned process is significantly more elaborate, pain staking, costly and time consuming than was found for the smaller municipal application. The primary differences are as follows:

- The municipal facility was offered a "one stop" process by the City of Irvine. The building department forwards sets of plans to the interested agencies.
- The micro turbine was sub-jurisdictional to the permitting authority of the SCAQMD.
- Since the refinery was not, it had to choose a location carefully as to avoid being within 1000 feet of a school, for if they were, a 30 day notice would have been required to the following:
    - Parents of all students at schools within _ mile of the source;
    - Residents within 1000 feet of the source; and
    - Businesses within 1000 feet of the source.
- Since the micro turbine would have actually on school property, the office of the state architect would have had to approve the municipal project if there were any significant modification to the building in which it was housed. This could take from between 3 to 6 months and could have entailed bringing the building up to any new standards that had been put in place subsequent to the building's original construction.
- Paramount Petroleum is a SCAQMD "RECLAIM" (Regional Clean Air Incentives Market) facility. As such credits obtained through their own or others reduction in oxides of nitrogen emissions had to be acquired (they were acquired through the shut down of the boilers).
- Costly add on emission control equipment (both in terms of equipment to reduce emissions and continuous monitoring of the subject emissions) was required of Paramount Petroleum. It would not have been required of the municipal facility.
- Paramount Petroleum's size requires a Federal Title V filing. This imposes new, monitoring, record keeping and reporting requirements.
- A conditional use permit (CUP) and its modification to accommodate the CHP facility is required of Paramount Petroleum by the city of Paramount and such is not required of the municipal facility.
- A much more thorough and painstaking review of the project's environmental impact under the California Environmental Quality Act is required of the refinery as a result of its size.

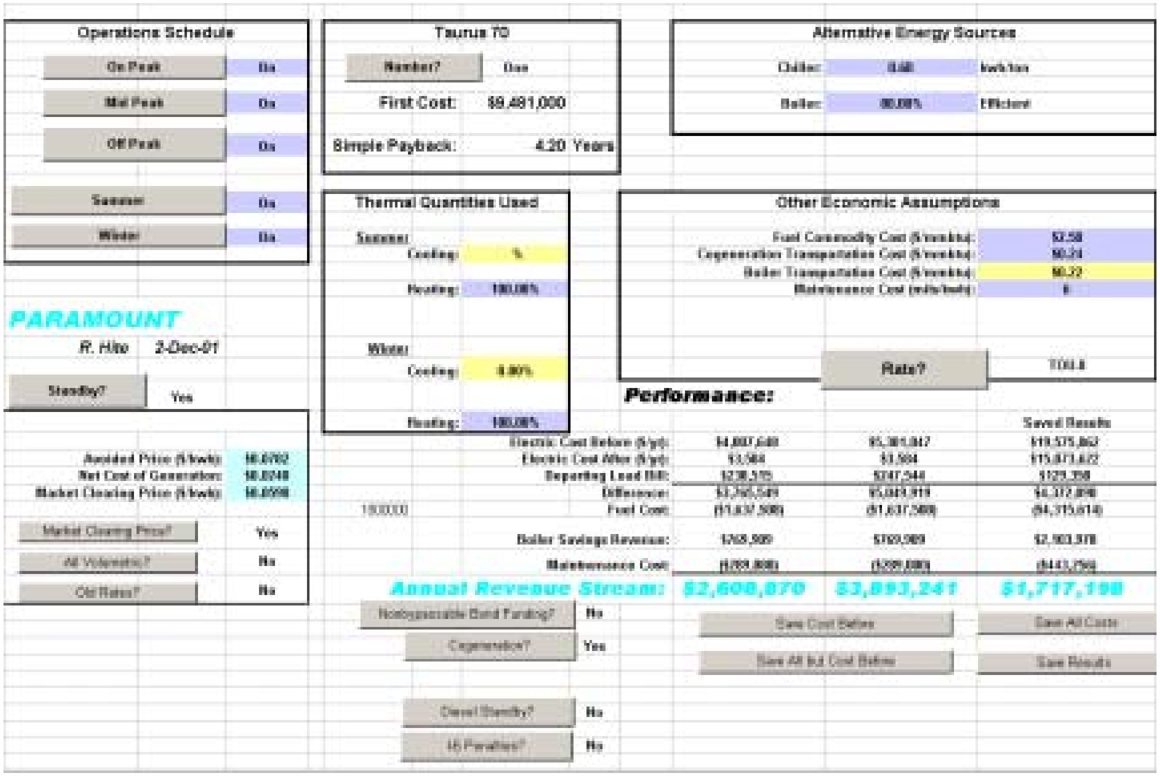
The Social Agenda

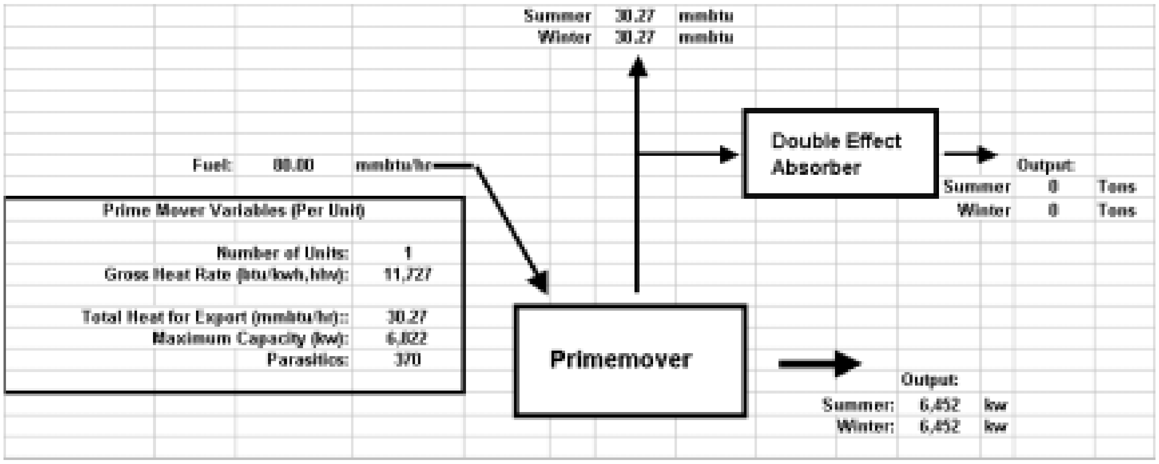
There are a number of indices associated with a project such as this that advance an appropriate social agenda. These are presented in Table 18:

Table 18. Indices For The Social Good

Capacity this Project	6.5 MW
Annual Natural Gas Equivalent Energy Savings	155 million cubic feet
Number of American Homes Served by Energy Savings	1,900
Number of American Cars Needed Off of Highways to Achieve a Similar Reduction in CO_2 Emissions	2,400
Number of American Cars Needed Off of Highways to Achieve a Similar Reduction in NO_x Emissions	14,800

Appendix: Sample Analysis (Paramount)





Load and Billing Before

Electricity Rate Calculator

Southern California Edison
TOU-8

Inputs:	January	February	March	April	May	June	July	August	September	October	November	December	Total
Monthly maximum demand, MMD, On-Peak (kW)	[redacted]					5,500	5,500	5,500	5,500	[redacted]			
Monthly maximum demand, MMD, Mid-Peak (kW)	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	
Monthly maximum demand, MMD, Off-Peak (kW)	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	
Monthly electricity consumption, On-Peak (kWh)	[redacted]					[illegible]	[illegible]	[illegible]	[illegible]	[redacted]			[illegible]
Monthly electricity consumption, Mid-Peak (kWh)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Monthly electricity consumption, Off-Peak (kWh)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Highest total MMD during prior 11 months (kW)	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	
Rate Calculation:							[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
Customer Charge	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Demand Charge - Facility Related	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Demand Charge - Time Related:													
On-Peak	$0.00	$0.00	$0.00	$0.00	$0.00	[illegible]	[illegible]	[illegible]	[illegible]	$0.00	$0.00	$0.00	[illegible]
Mid-Peak - Generation	$0.00	$0.00	$0.00	$0.00	$0.00	[illegible]	[illegible]	[illegible]	[illegible]	$0.00	$0.00	$0.00	[illegible]
Energy Charge:													
On-Peak - Generation (CTC)	$0.00	$0.00	$0.00	$0.00	$0.00	[illegible]	[illegible]	[illegible]	[illegible]	$0.00	$0.00	$0.00	[illegible]
Mid-Peak - Generation (CTC)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Off-Peak - Generation (CTC)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Sub-Total - $	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
mid peak average cost	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
on peak plus mid peak average cost	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Taxes/Other Charges (?????)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total ($)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Monthly Average Unit Cost ($/kWh)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Generated Load

Electricity Rate Calculator (Billing Data 6/00 - 11/00, balance estimated)

Southern California Edison
TOU-8

Inputs:	January	February	March	April	May	June	July	August	September	October	November	December	Total
Monthly maximum demand, MMD, On-Peak (kW)	[redacted]					5,500	5,500	5,500	5,500	[redacted]			
Monthly maximum demand, MMD, Mid-Peak (kW)	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	
Monthly maximum demand, MMD, Off-Peak (kW)	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	
Monthly electricity consumption, On-Peak (kWh)	[redacted]					752,143	683,714	730,714	616,343	[redacted]			2,809,714
Monthly electricity consumption, Mid-Peak (kWh)	1,511,714	1,350,500	1,503,214	1,532,143	1,511,714	1,003,714	1,046,571	1,096,071	1,011,214	1,503,214	1,309,143	1,511,714	16,395,929
Monthly electricity consumption, Off-Peak (kWh)	2,580,286	2,337,500	2,508,786	2,427,857	2,580,286	2,192,143	2,347,214	2,295,214	2,274,643	2,508,786	2,519,857	2,580,286	29,174,757
Highest total MMD during prior 11 months (kW)	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	
Rate Calculation:													
Standby Charge	$5,500.00	$5,500.00	$5,500.00	$5,500.00	$5,500.00	$5,500.00	$5,500.00	$5,500.00	$5,500.00	$5,500.00	$5,500.00	$5,500.00	$66,000.00
Demand Charge - Time-Related:													
On-Peak	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mid-Peak	$0.00	$0.00	$0.00	$0.00	$0.00	$11,330.00	$11,330.00	$11,330.00	$11,330.00	$0.00	$0.00	$0.00	$45,320.00
	$0.00	$0.00	$0.00	$0.00	$0.00	$11,330.00	$11,330.00	$11,330.00	$11,330.00	$0.00	$0.00	$0.00	$45,320.00
Energy Charge:													
On-Peak	$0.00	$0.00	$0.00	$0.00	$0.00	$1,986.05	$1,841.97	$1,829.89	$1,779.74	$0.00	$0.00	$0.00	$7,417.65
Mid-Peak	$3,980.93	$3,586.14	$4,179.69	$4,044.86	$3,980.93	$2,800.29	$2,762.95	$2,893.83	$2,669.61	$4,179.69	$3,887.34	$3,980.93	$42,797.28
Off-Peak	$6,811.95	$6,171.00	$6,623.18	$6,409.54	$6,811.95	$5,787.26	$6,197.97	$5,950.17	$6,005.05	$6,623.19	$6,787.06	$6,811.95	$77,830.38
- Total	$16,292.89	$15,257.44	$16,302.88	$15,954.40	$16,292.89	$27,284.40	$27,832.08	$27,832.08	$27,284.40	$16,302.89	$15,954.40	$16,302.88	$0.0008
Taxes/Other Charges (?????)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total ($)	$16,292.89	$15,257.44	$16,302.88	$15,954.40	$16,292.89	$27,284.40	$27,832.08	$27,832.08	$27,284.40	$16,302.89	$15,954.40	$16,302.88	$239,515.28
Monthly Average Unit Cost ($/kWh)	$0.0040	$0.0041	$0.0040	$0.0040	$0.0040	$0.0059	$0.0058	$0.0058	$0.0059	$0.0040	$0.0040	$0.0040	$0.0058

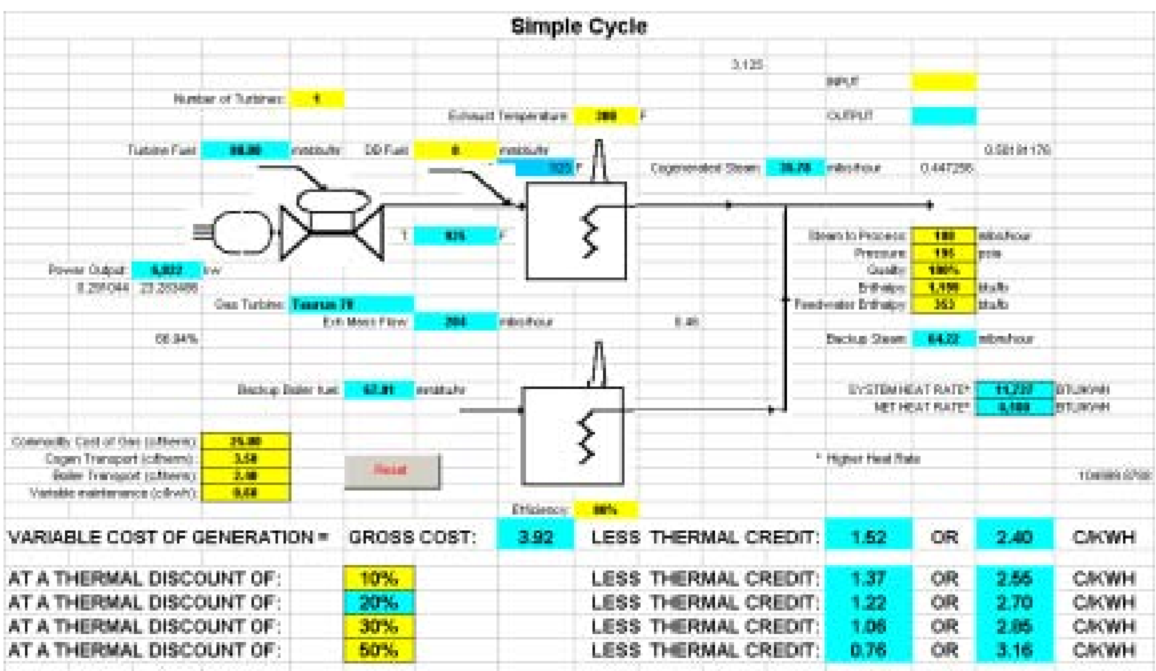
New Load

Electricity Rate Calculator

Southern California Edison
TOU-8

Inputs:	January	February	March	April	May	June	July	August	September	October	November	December	Total
Monthly maximum demand, MMD, On-Peak (kW)						0	0	0	0				
Monthly maximum demand, MMD, Mid-Peak (kW)	0	0	0	0	0	0	0	0	0	0	0	0	
Monthly maximum demand, MMD, Off-Peak (kW)	0	0	0	0	0	0	0	0	0	0	0	0	
Monthly electricity consumption, On-Peak (kWh)						0	0	0	0				0
Monthly electricity consumption, Mid-Peak (kWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Monthly electricity consumption, Off-Peak (kWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Highest total MMD during prior 11 months (kW)	0	0	0	0	0	0	0	0	0	0	0	0	

Rate Calculation	January	February	March	April	May	June	July	August	September	October	November	December	Total
							0	0	0	0	0		
Customer Charge:	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$3,583.80
Demand Charge - Facility Related	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Demand Charge - Time-Related:													
On-Peak	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mid-Peak	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy Charge:													
On-Peak	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mid-Peak	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Off-Peak	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sub-Total - $ - Generation	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$3,583.80
Taxes/Other Charges (??????)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total ($)	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$298.65	$3,583.80
Monthly Average Unit Cost ($/kWh)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!



Southern California Edison					
TOU-8					
Rate Components					
Component	**CTC**	**PX**	**Non-Gen./ Other**	**Total**	
Customer Charge ($/Mo)	123.98		174.67	298.65	
Demand Charge ($/kw):					Gen Chg
Facilities	2.66		-2.01	0.65	0.35
Time-Related - On-Peak	0.00		17.55	17.55	
Mid-Peak	2.06		0.74	2.80	
			.		
Energy Charge ($/kWh):					
Summer - On-Peak	0.00264	0.00000	-0.00118	0.15428	
Mid-Peak	0.00264	0.00000	-0.00118	0.07137	
Off-Peak	0.00264	0.00000	-0.00118	0.06234	
Winter - Mid-Peak	0.00264	0.00000	-0.00118	0.07880	
Off-Peak	0.00264	0.00000	-0.00118	0.06315	

Annual Fixed Costs	$350,000										
Ad Valorem Taxes	1.5%		Freeze		UnFreeze						
Debt Interest	6.0%										
Debt/Equity Ratio	50.0%		Before and After Rates?		Same						
Income Tax Rate	42.0%										
Year	0.00	1	2	3	4	5	6	7	8	9	10
First Cost	$9,481,000				-$2,229,808.36	-0.853169489					
Net Energy Revenue		$3,902,269	$3,902,269	$3,902,269	$2,608,870	$2,608,870	$2,608,870	$2,608,870	$2,608,870	$2,608,870	$2,608,870
Annual Fixed Costs	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000	$350,000
Ad Valorem Taxes		$142,215	$142,215	$142,215	$142,215	$142,215	$142,215	$142,215	$142,215	$142,215	$142,215
Debt Service		$644,082	$644,082	$644,082	$644,082	$644,082	$644,082	$644,082	$644,082	$644,082	$644,082
Debt Interest		$284,430	$262,851	$239,977	$215,731	$190,030	$162,786	$133,909	$103,298	$70,851	$36,457
Depreciation		$948,100	$948,100	$948,100	$948,100	$948,100	$948,100	$948,100	$948,100	$948,100	$948,100
Income Taxes		$914,580	$923,624	$933,231	$480,166	$418,366	$422,423	$434,551	$447,408	$461,036	$475,481
After Tax Cash Flow:	**-$5,090,500**	**$1,851,412**	**$1,842,349**	**$1,832,742**	**$1,072,387**	**$1,061,592**	**$1,050,150**	**$1,038,022**	**$1,025,166**	**$1,011,537**	**$997,092**
		$3,552,269	$3,552,269	$3,552,269	$2,258,870	$2,258,870	$2,258,870	$2,258,870	$2,258,870	$2,258,870	$2,258,870
IRR:	**26.55%**										
Payback:	**2.7**										

DG Permit Streamlining

SUMMARY

One of the major obstacles to successful deployment of distributed generation (DG) exists at the local permitting level. The primary local permit processes are conducted by multiple agencies, e.g., city and county governments, air districts. Obtaining approvals from these entities can be time-consuming and costly, as well as confusing to project developers who are not well versed in the local government requirements and procedures and to agency personnel who are not knowledgeable regarding DG technologies. Consequently, the deployment of DG may be hindered because of the involved and costly permit processes. In order to overcome these obstacles, the permit process must be understood, and opportunities to reduce confusion and costs should be developed.

The levels of government involvement and review and approval obstacles were presented in the California Energy Commission (Energy Commission) December 2000 report, "Distributed Generation: CEQA Review and Permit Streamlining" (P700-00-019). The three permit processes identified by the Energy Commission included land-use approvals, building permits and air permits with particular emphasis on the requirements for approval and permits, as well as opportunities identified to streamline the California Environmental Quality Act (CEQA) review and permitting processes. As a result of this effort, the Energy Commission Staff's recommendations (focused on assisting local governments) presented in last year's report included information dissemination (e.g., training, technical assistance, guidance development to local governments), amendments to the CEQA guidelines for certain categorical exemptions of select DG equipment, and involvement in inter-agency DG-related efforts (e.g., California Air Resources Board, local permitting jurisdictions, local government planning). However, the Energy Commission's recommendation to focus on assistance to local governments rather than private DG developers was stated in last year's report as follows: "This approach would enable the Energy Commission to maintain its neutrality regarding the acceptability of individual DG projects, while still facilitating DG project deployment." Therefore, in order to identify potential obstacles and streamlining opportunities for DG project developers, an evaluation of two case studies was initiated.

Two case studies – DG project development at a municipality site and at an existing industrial site – are discussed in this report. The current permitting process and practices for each site were identified based on a series of discussions with local agencies and with site personnel. Furthermore, the permit process in other areas of California was also considered in order to present a broad-brush discussion of similarities and differences that may also be used to describe obstacles and streamlining opportunities. Recommended streamlining opportunities were based on previous Energy Commission efforts noted above and on discussions with agency and site personnel. From this information, cost savings opportunities for the two case studies were qualitatively assessed, and approximate statewide cost savings associated with the recommended streamlining opportunities were estimated based on a market assessment of combined heat and power

in California. A rough estimate of nearly $70 million may be saved statewide over the next 15 years with improvements in the agency review and approval process. These improvements include useful resources and tools that can be developed, so project developers may access these in the early project planning and development phases in order to minimize project costs. Furthermore, the implementation of these resources and tools may provide certainty to the approval process not only for the agencies but also for the developers seeking project approval for projects throughout the state, thus facilitating the deployment of DG technologies in California.

Introduction

The environmental approval process for siting and permitting of a distributed generation (DG) source involves multiple agencies with varying objectives. For all DG projects, construction and operating approvals must be obtained from local jurisdictions. The more involved approval procedures are those required by the local planning and building departments and the air district. Local planning and building departments must ensure that a DG project complies with local ordinances (e.g., noise, aesthetics, set-backs, general plan and zoning, land use), and standards and codes (e.g., fire safety, piping, electrical, structural, etc.). Approvals may be in the form of a permit or license issued after an agency has verified conformance with requirements, or may be in the form of a program (e.g., landscaping, noise monitoring) that must be developed to ensure the environmental impacts are mitigated. The number of approvals will vary depending on project characteristics such as the size and complexity, geographic location, the extent of other infrastructure modifications (e.g., gas pipeline, distribution system, sewer connections), and potential environmental impacts of construction and operations.

This report provides an overview of the local permit processes and practices associated with the installation and operation of DG technologies. Two southern California locations were considered – a municipality and an existing industrial facility – as cases to describe the permit process and identify potential streamlining opportunities. In both cases, natural gas fired DG technologies were selected for siting. For the municipality case, gas reciprocating engines or microturbines were considered for the City of Irvine. A small industrial gas turbine was considered for Paramount Petroleum Corporation's Refinery (Paramount) in the City of Paramount, which served as the industrial facility scenario. In both cases, the governing air quality district is the South Coast Air Quality Management District (SCAQMD); other approvals are specific to the local agencies' jurisdictions. The approval process in other areas of California is also highlighted in order to present a broad-brush discussion of similarities and differences.

Scope of Work Objectives

This report presents an overview of DG project development information that can facilitate in need to obtain approvals and overcome potential obstacles in the process. Based on the evaluation of the two case studies, recommendations are provided for improvements in the approval process that can be useful for siting and permitting elsewhere in California. The discussions are based on the two cases, as well as permitting experiences in other areas of California.

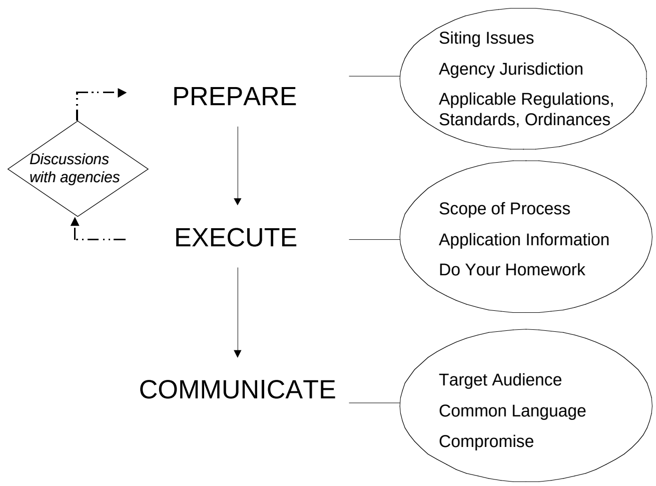
As a framework for this overview, the California Energy Commission (Energy Commission) effort to identify of DG siting issues was considered. Specifically, the Energy Commission report titled "Distributed Generation: CEQA Review and Permit Streamlining" (December 2000, P700-00-019) served as a resource to characterize the local permit and approval processes for the two DG cases. Recommendations regarding process improvements and permit streamlining are based on several issues identified in the Energy Commission report. Additionally, the current effort of the California Air Resources Board (CARB) regarding DG certification and control technology guidance was also considered. Because air quality permit requirements directly affect fossil fuel-fired technologies, CARB is in the process of adopting its guidance pursuant to Senate Bill 1298 (SB 1298) for the certification of exempt DG sources and BACT guidance for DG sources requiring permits.

It should be noted that, originally, one aspect of this scope was to review the Silicon Valley Uniform Code (SVUC) Program for elements specific to DG and include recommendations based on this review. The SVUC effort was part of the "Joint Venture: Silicon Valley Network" (JVSV) organization's efforts to streamline the development process; this included addressing the uniform building code, regulatory streamlining and the permitting process among the various cities and counties in the JVSV organization. Rather than specifically evaluate elements of the SVUC that may be applicable to DG siting, the efforts of the JVSV are discussed as an example of an organizational approach for overall permit streamlining.

Project Development Objectives

Although distributed generation (DG) projects continue to be sited and permitted throughout the state and nation, local requirements can result in unanticipated delays that directly translate to increase project costs. The associated development costs and risk profiles of the project developers must be well thought out. The complexity of a DG project will likely add to the level of agency interaction. Most notably, with DG technologies firing fossil fuels (e.g., natural gas, propane, diesel), concerns may be raised regarding air quality impacts. That is, environmental regulatory and local government agency approval costs, in an uncertain environment and locale for which project planning has not been mapped out, may approach 10-20% of project-installed costs. These costs may include, but are not limited to, the following: air pollution control equipment, noise abatement equipment or structures, landscape-related mitigation, and agency review and approval fees. Consequently, project economics must be fully evaluated. Figure 16 presents a very general, three-step approach to initiating discussions with approval agencies.

Figure 16. Discussions with Agencies and Public



As previously discussed, the size of a DG project will determine the level of air agency involvement. For relatively small sites where the DG unit is the only pollutant emitting equipment, local requirements will typically govern. For larger facilities with existing air permitted equipment, additional consideration of federal requirements may be necessary. Environmental regulatory and land use/planning issues must be considered early on in the project feasibility, engineering design and facility operations scenarios, regardless of whether a DG project is for a photovoltaic (PV) system, microturbine, gas turbine, or reciprocating engine. Three main considerations include: (1) site selection, (2) equipment location, and (3) equipment operating scenarios.

Site selection will determine the agencies (and local community) involvement. This includes such entities as the city or county planning agency, the fire marshal at the respective fire department/authority, the city or county building department, the environmental health department, and the air district. Equipment location on a particular land parcel will involve the evaluation of zoning compatibility, noise issues, aesthetics, and projected air quality modeling impacts. Finally, the equipment operating scenarios will determine the extent for mitigation of environmental impact, particularly consideration for air pollution control requirements and noise issues. The following sections highlight general project development considerations.

Project Development

Project development involves several issues that must be thoroughly considered. Regardless of the size of a DG project, a developer must identify an acceptable project risk profile, properly design the DG project, construct and install the equipment and operate the facility. These elements must be addressed in the early stages of project development in order to maneuver the regulatory approval processes that affect each phase of a DG project. Each phase of a project may involve several contractors, multiple scheduling milestones, and budgetary requirements and limitations. Because each phase is not clearly delineated in the development process, addressing the competing interests of the regulatory approval agencies for each can be challenging.

Resolving the conflicts and unanticipated agency responses that arise can be burdensome and result in unnecessary project expenses and delays. Delays in obtaining approvals are inevitable but can be minimized with proper project planning. Typically, it is expected that regulatory agency involvement in small DG projects will be minimal. Although this may have been the historical perspective for some project developers, current regulatory agency practices are resulting in a rigorous review of project design and operations even for smaller capacity projects. Planning should include identifying the following: alternative sites and equipment options, fatal flaws (e.g., ability to meet stringent regulatory requirements), regulatory approval requirements, and startup and performance testing

Project Alternatives

A broad definition of the "base case" project should be developed in order to later determine the feasibility of the DG project. Project characteristics should include an outline of the equipment type, generating capacity, operating schedule, fuel types, and ancillary equipment. Site characteristics should include consideration of the surrounding and existing infrastructure such as water supply, fuel supply, distribution, and land use availability and compatibility. With respect to air quality, project emissions and control technology proposed to meet best available control technology (BACT) requirements must be determined.

Feasibility of Project

For all project alternatives, a fatal flaw analysis should be conducted in order to determine the ease or difficulty of project approval. Alternatives should be prioritized based on the project developer's acceptable risk profile. Budget constraints may include project-financing options, contractual agreements, and facility operations responsibility (e.g., own, operate, lease). Concurrent with this evaluation is whether the selected site is suitable and any limitations can be readily overcome. Limitations may include gas distribution, land use, remediation requirements, environmental issues (e.g., air emission credits, water supply, noise), and most notably, the local political and regulatory agency setting. This element of project planning should result in identifying the preferred project and other alternative project contingencies. Alternatives include generation capacity requirements, different site locations, equipment selection, type of fuel(s), and control technology equipment options. At this stage of project development, preliminary discussions with is be helpful to minimize the "guess-work" prior to initiating project permitting efforts.

Preferred Project Licensing

The applicable approval requirements and procedures must be identified. Local issues and policies that are not written regulatory requirements must be addressed. In all cases, if there is a potential for not meeting a particular requirement, alternatives or sufficient mitigation will be necessary. The result of this effort should be a clear understanding of the milestones to obtain approvals coincident with the ability to initiate construction. Depending on the local community, outreach efforts may be helpful to address potential community concerns.

Project Construction and Operations

Agency approvals will include conditions for construction and operations. In some cases, additional programs and plans must be developed for long-term operations. Depending on the DG project characteristics, these may include industrial and worker safety programs, site and management personnel training, storm water runoff management and practices, fire protection and safety, and materials management (e.g., hazardous materials, hazardous waste, solid waste) for cleaning chemicals. Particularly for industrial facilities, in order to address the operational issues associated with environmental impacts, these programs and plans are typically included in standard operating procedures. With respect to air quality requirements, compliance demonstration is required for meeting and record keeping of emissions, fuel usage, operating times, and emissions source testing. With respect to planning agency issues, a conditional use permit may be issued that identifies additional mitigation such as landscaping plans, air pollution control, architectural treatments and noise abatement.

Approval Agency Objectives

Project characteristics are evaluated for conformance with an agency's jurisdictional requirements and policies. Additionally, some DG project approval actions may require public involvement. For example, a planning agency may require public review of actions such as the issuance of a conditional use permit. Also, fossil fuel fired DG projects will be evaluated for its air toxic emissions impacts. If a DG source is sited within 1,000 feet of a school, there is a separate public notification requirement that is managed by the local air district and the DG developer. The parents of the students at these schools (and other students at schools within _-mile of the facility), as well as residents and businesses with 1,000 feet of the DG source, must be notified of the projected air toxic emission impacts from the equipment.

Overview of the Approval Process

The approval procedures for a DG source will generally be similar regardless of whether a DG source is sited as part of a municipality effort or an industrial facility expansion. Because there is not a "one-stop" permitting process for the approval of DG sources, it is necessary to obtain permits and approvals from multiple organizations prior to construction, and in some cases, as prior to operation. The number of permits and approvals will vary depending on project characteristics such as the size and complexity of a project, the geographic location, the extent of other infrastructure modifications (e.g., gas pipeline, distribution), and the potential environmental impacts of construction and operations.

The primary approvals that DG sources must obtain consist of the following:

- Local jurisdiction pre-construction and construction approvals
    - Planning department land use and environmental assessment/review
    - Building department review and approval of project design and engineering
    - Air district approval for construction
- Local distribution company approval
    - Interconnection study
    - Natural gas pipeline connection/supply
- Local jurisdiction post-construction and operation approvals
    - Planning department and building department confirmation and inspection of installed DG source
    - Air district confirmation that DG emissions meet emissions requirements

Although there are other approvals needed for the installation and operation of a DG source, the above approvals are typically the drivers for DG siting; that is, the approvals from planning, building and air agencies are expected to be the more involved activities that require frequent interaction with the approval entities. Delays in responding to these entities' requests can hinder approval. Depending on the size and type of the DG source, other necessary approvals can include obtaining permits from local agencies such as the following: environmental/health department, public works, regional water quality control board, fire department, and water/wastewater district.

There may also be an inter-dependency for agency approvals; approvals from other agencies and organizations may be contingent on obtaining approvals from those agencies that issue planning, building and air quality approvals, and vice-verse. For example, in the San Francisco Bay Area, the local air district (Bay Area Air Quality Management District) will not issue a final air permit until a project subject to CEQA[57] review has obtained its CEQA-related approval, e.g., conditional use permit, negative declaration, etc. Table 19 highlights organizations for which approvals may be required. It should be re-emphasized that the number of approvals needed for a DG source will vary dependent on the type of technology, environmental impacts and location.

Table 19. Agencies Potentially Involved in DG Siting Approvals

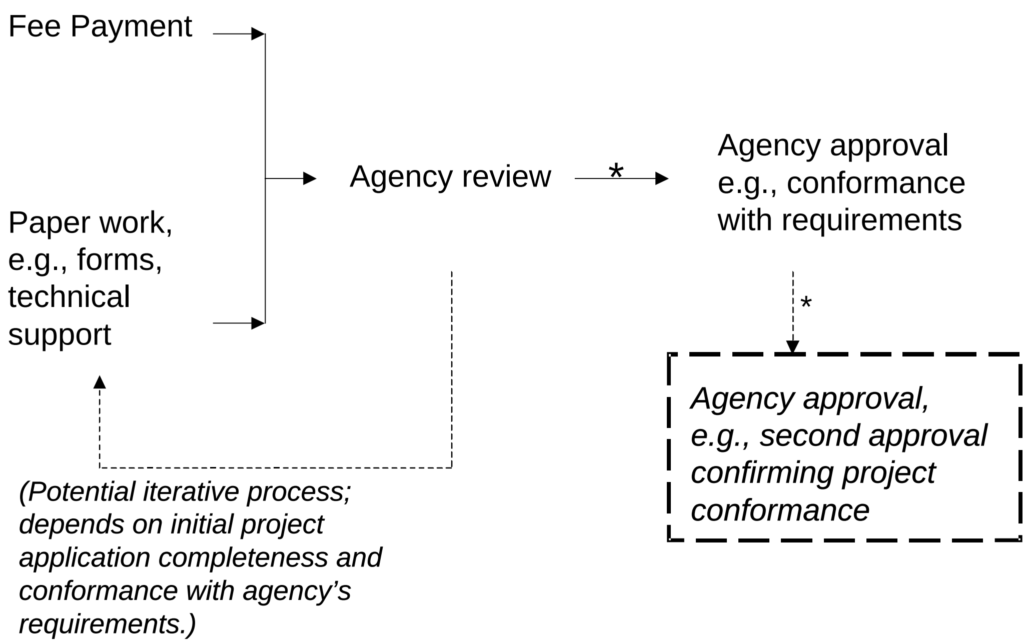
Agency / Organization	Jurisdiction / Discipline
Air district	Air quality permitting. Primary area is the control of air pollution to protect public health. May have CEQA responsibility as lead agency or responsible agency. Compliance with federal and state Clean Air Act requirements. Jurisdiction defined by county limit or a group of counties comprising an air district.
Planning department	Environmental assessment. Primary areas are land use and zoning issues. May have CEQA responsibility as lead or responsible agency. Project impacts evaluated for conformance and environmental impacts. Noise impacts evaluated by this agency. Jurisdiction defined by city or county limit.
Building department	Building permit approvals. Approvals issued for projects in conformance with building code requirements. Also ensures project design is consistent with industrial and worker safety. Jurisdiction typically defined by city or county limit.
Fire department	Fire protection and safety. Approvals issued for projects in conformance with fire code requirements. May also be organization responsible for portions of environmental health-related requirements. Jurisdiction typically defined by city or county limit.
Environmental health	Public health and safety. Approvals issued for projects in conformance with federal and state hazardous materials and waste management requirements. May also have responsibilities associated with fire and building code issues. Jurisdiction defined by city or county limit.
Water and wastewater district; public works	Water supply and discharge. Approvals issued for allowable discharge to sewer system; evaluates waste streams that may enter various bodies of water (e.g., lakes, streams, bays, estuaries, coastal waters, etc.). Ensures compliance with storm water requirements. Project conformance with federal Clean Water Act and local water and wastewater quality requirements. Jurisdiction defined by city or county limit.

Regardless of which agencies are involved in granting approvals, the following describes the general approval process that a DG developer can expect from each, as presented in Figure 17.

1. Fee payment – Pay fee for agency review time and approval/permit issuance, e.g., flat fee, time and materials
2. Paper work concurrent with fee payment – Complete necessary application forms
    a. Standard application form and project specific forms, e.g., equipment specific forms may be specified
    b. Project description needed, e.g., equipment, site location, operations
    c. Agency conformance, e.g., demonstrate project conforms to agency regulatory requirements
    d. Data compilation and submittal, e.g., provide technical support information
3. Agency review – Agency determines completeness of information
    a. Respond to agency request, e.g., incomplete application requires more information, clarification needed

4. Agency approval – Agency completes review and issues permit or approval

Figure 17. General Agency Approval Process



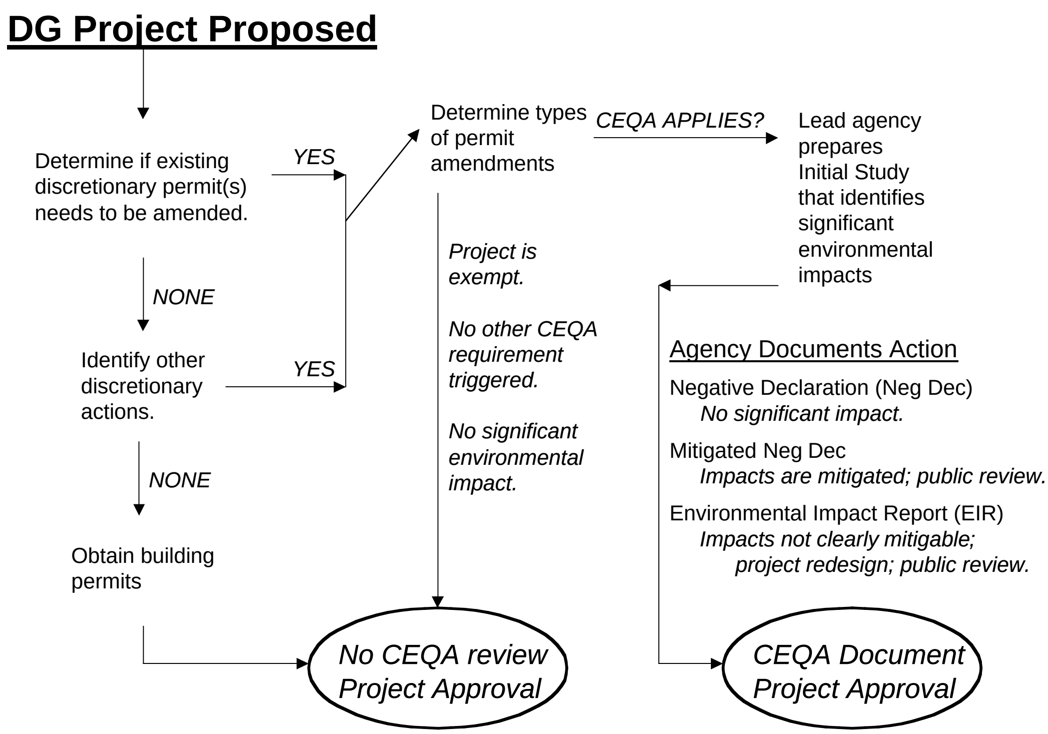
** Public review and comment may be required at this point.*

For some agencies, an additional approval may be needed to confirm the final installed DG project is in conformance with agency requirements and is constructed as presented in the initial application. As a result, an agency may conduct a site inspection and subsequently issue an additional approval. A public review and comment period may also be required; this depends on the agency's thresholds for public review. Under these circumstances of public review, a DG project developer can expect at least an additional 1-2 months for project approval, assuming that public comments can be readily addressed and impacts (real and perceived) can be mitigated or eliminated. With respect to the three areas of primary consideration – planning, building and air quality – the following provides an overview of each area's approval process.

Planning Agency

The local planning agency is responsible for conducting an environmental assessment of the DG project. The criteria for this assessment are based on the California Environmental Quality Act, or CEQA. The lead agency for CEQA review is often the city jurisdiction where the DG project is proposed, or in some cases, it may be the county jurisdiction.[58] Most DG projects will qualify as a type of project requiring some form of approval that requires a discretionary decision; because a discretionary decision is involved, a CEQA review will be performed. Figure 18 highlights the CEQA review process.

Figure 18. General Overview of CEQA Review Process



CEQA review involves an evaluation of a DG project's environmental impact. A preliminary review of the project is conducted to determine CEQA applicability; an initial study is conducted, and a CEQA document is prepared commensurate with the agency's evaluation. It may be as straightforward as the completion of an "environmental checklist" that demonstrates the project has no impacts, to a more complex approval that requires a formal report identifying agreed upon mitigation of environmental impacts. The latter will typically require that the planning agency coordinate with other agencies involved in evaluating environmental impacts, e.g., air district, environmental health department.

With respect to the smaller and non-air polluting type of DG projects, it is expected that the more involved CEQA review would not be applicable because of exemptions or because of no significant impacts. For fossil fuel-fired projects requiring air permits, generally, nothing more than a negative declaration or mitigated negative declaration would be expected if CEQA review is triggered. If the project triggers a threshold for public review, the local planning commission may hold a public workshop(s) in order to issue its final approval. It is expected that the more involved and complex Environmental Impact Review (EIR) process would not be required for most projects because the DG projects under consideration for this report are relatively small and do not to trigger an EIR process.

Issues that a planning agency considers include: land use compatibility, conformance with zoning requirements, and environmental impacts. Each jurisdiction has a set of defined land uses, e.g., residential, commercial, industrial, mixed use, and subcategories of each. For each land use, certain types of activities are allowable and may be prescribed by zoning ordinances. There will be some ordinances where DG projects are readily allowed or are explicitly prohibited. Under some circumstances of incompatible land use, it may necessary to seek an amendment to the land use policies and/or a zoning ordinance prior to agency approval. With respect to environmental impacts, Table 20 highlights the environmental impacts that may be considered by the planning agency.

Table 20. Planning Agency's Review Consideration for Environmental Impacts

Aesthetics	Agriculture Resources	Air Quality
Biological Resources	Cultural Resources	Geology / Soils
Hazards & Hazardous Materials	Hydrology / Water Quality	Land Use / Planning
Mineral Resources	Noise	Population / Housing
Public Services	Recreation	Transportation / Traffic
Utilities / Services Systems	Mandatory Findings of Significance	

As part of the agencies review process, if it is determined that the DG project has some level of environmental impact that is significant or considered adverse, the project's impacts must be mitigated to levels acceptable to planning agency. Consequently, it is important that the DG project be designed to meet the planning agency review criteria and/or minimize or be designed to eliminate the environmental impact. Examples of mitigation measures include further reducing or controlling air pollutant emissions, providing structural enclosures that abate noise impacts, contributing to a habitat preservation program, or implementing a particular landscaping plan.

With respect to similarities or differences among planning agencies, agencies' reviews are governed by the state CEQA requirements for reviewing environmental impacts. However, each planning agency will have local ordinances that also apply to DG projects. Therefore, review of environmental impacts can vary. The siting of the same type of DG project in one jurisdiction will not necessarily result in the same type of review and approval procedures of another jurisdiction. Contributing factors to the differences in agencies' reviews include: nearby affected communities, local ordinances, nearby affected plant and wildlife species, understanding of DG technology environmental impacts, and inter-agency coordination efforts.

Building Department

The local building department is responsible for ensuring that a DG project's design and operation will conform to building codes, e.g., local and national building codes; in addition, conformance with fire codes is also reviewed. Often, the building department is part of a city's planning agency organization. Building officials will review submitted building permit applications and construction plans. Most DG projects must obtain building permits.[59] Permit approval is contingent upon review of construction drawings representing project design characteristics such as mechanical, electrical, plumbing and structural designs; hazardous materials storage; and fire protection and safety.

As part of the building department's review process, it is important to ensure that the building officials understand the DG technology in order to properly evaluate conformance with building codes. Moreover, the site inspections are a key element to project approval. The DG project must pass site inspections and be approved for occupancy in order to proceed with commencing operations. Consequently, it is important that the DG project be designed to conform to a variety of codes to minimize or eliminate project redesign or reconstruction, or delays start-up.

With respect to similarities or differences among building departments in different jurisdictions, although building departments base their approvals on the same type of codes, each building department may have different local ordinances and ordinances that are more restrictive than the state building codes. Most notably, the differences in building departments' requirements and evaluation were the basis for the development of the Silicon Valley Uniform Code (SVUC) Program. The SVUC is a result of multiple cities and counties collaborating to develop consistent building codes across their jurisdictions. This was part of a larger effort of regulatory streamlining for local businesses in the Silicon Valley region of Northern California. As a result, the state building code amendments that were adopted by the respective jurisdictions were evaluated and consolidated as part of the SVUC effort, thus significantly reducing the inconsistencies among each jurisdiction.

Air Agency

The local air district is responsible for issuing permits to construct and operate a DG project that emits air pollutants at levels requiring a permit. The criteria for this agency's approval are based on local regulations that fulfill the requirements of the federal and state Clean Air Acts. An air permit is required for those DG sources that emit a certain level of air pollutants and/or that exceed a certain capacity. In many cases, non-air pollutant emitting or relatively low-emitting DG projects such as photovoltaics, fuel cells and microturbines do not require an air permit; however, most fossil fuel fired DG projects will require an air permit. For a DG project requiring an air permit, emissions must meet the agency's specified controlled emission standards. This may require add-on control technology. In addition, a DG project must be evaluated for air toxic impacts. Finally, after the DG equipment is installed, the exhaust emissions must be tested to ensure the projected emissions meet the agency's requirements. For larger projects or projects at a facility where there is a facility-wide emission limit or some other existing constraints on operations, emission reduction credits (ERCs) may be needed.[60] Figure 19 presents the 35 California Air Districts.

Figure 19. California Air Districts

Source: CARB website - arbis.arb.ca.gov/emisinv/maps/statemap/dismap.htm

Each California air district has its own set of regulations. Regulations differ primarily because of a district's status for meeting the federal or state ambient air quality standards. Districts not meeting the ambient air quality standards will tend to have more stringent emission standards and potentially more complex permitting requirements.

With respect to the type of DG projects considered for this overview, microturbines are currently exempt from permitting or any form of air district approval. However, gas reciprocating engines and small industrial gas turbines must obtain air permits. In many cases throughout California, BACT is required. BACT is a prescribed emission standard and/or control technology that must be met in order to obtain an air permit. The air district jurisdiction and cost-effectiveness of reducing emissions will determine the acceptable emission levels. Typical NOx BACT options for the two types of DG technologies are highlighted below in Table 21.

Table 21. Typical NOx Technologies for "Top-Down" BACT Options

Gas Turbine[(a)]	Lean Burn Engine[(a)]	Rich Burn Engine[(a)]
Zero Ammonia Technology[(b)] Selective Catalytic Reduction Dry Low NOx Combustors Steam / Water Injection	Selective Catalytic Reduction Pre-combustion chamber Turbocharge Aftercool Timing Retard	Non-Selective Catalytic Reduction Turbocharge Aftercool Timing Retard

NOTE: (a) Technologies may be used in combination.
(b) Zero ammonia technology includes consideration of SCONOx™ and catalytic combustion.

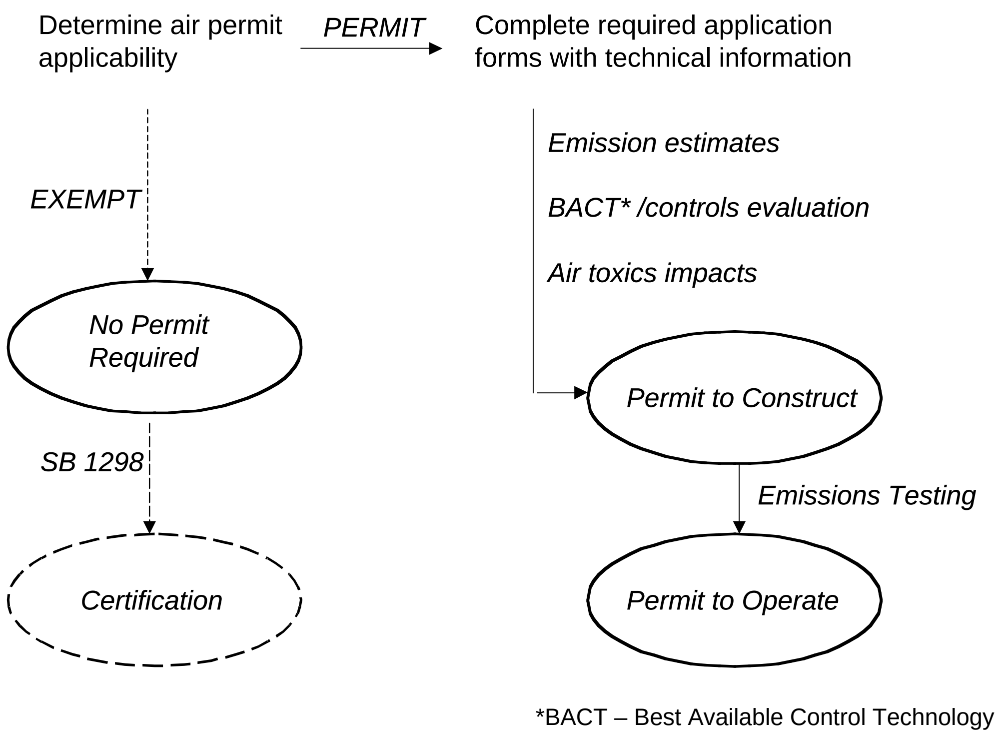
Issues that an air agency considers include: exemption thresholds (e.g., capacity, emission levels), controlled emission levels, type of fuel(s) fired, proximity to sensitive receptors (e.g., schools, day cares, hospitals), siting at a new location or an existing site (e.g., commercial building, industrial facility), health risk exposure of cancer and non-cancer combustion by-products, and a demonstration that projected emission levels are met via source testing.

With respect to similarities or differences among air districts, although districts' reviews are governed by the federal and state Clean Air Acts, as previously mentioned, each district has its own set of regulations. Most notably, districts typically have different BACT requirements. As a result of this widely recognized difference, legislation was passed in September 2000 for Senate Bill 1298 (SB 1298). As presented by CARB[61], SB 1298 is described as follows:

> Senate Bill 1298 (SB 1298), which was chaptered in September 2000, requires the Air Resources Board ("ARB" or "Board") to adopt uniform emission standards for electrical generation technologies that are exempt from air pollution control or air quality management district (district) permit requirements. The statute also directs the ARB to establish a certification program for technologies subject to these standards. SB 1298 focuses on electrical generation that is near the place of use, and define these sources as "distributed generation" (DG).
>
> SB 1298 mandates two levels of emission standards for affected DG technologies. The law requires that the first set of standards be effective on January 1, 2003, and reflect the best performance achieved in practice by existing electrical generation technologies that are exempt from district permits. The law also requires that, by the earliest practicable date, the standards be made equivalent to the level determined by the ARB to be the best available control technology (BACT) for permitted central station power plants in California.

Based on the current air quality permit approval process and upcoming SB 1298 efforts, currently exempt DG technologies will require certification by the CARB. DG technologies subject to air permitting will be subject to the air district district's consideration of the BACT guidance resulting from the SB 1298. Figure 20 presents an overview of the air quality permit process and includes reference to the potential outcome of the SB 1298 efforts.

Figure 20. General Air Quality Approval Process



It should be noted that slight differences might exist not only for the BACT emission levels but also for emissions testing requirements. Some air districts have specific source test methods for determining compliance of equipment exhaust emissions. Furthermore, a third-party source test firm typically conducts testing.

Case Studies of Municipal and Industrial Site Approval Process

As previously noted, a municipality and an existing industrial facility – City of Irvine and Paramount, respectively – were considered for evaluating permit-streamlining opportunities. Both are in southern California. Each case is described below. The three primary areas are discussed for each, however the most notable permit approval process – the air agency – is discussed in more detail.

Highlights of Municipal Site Approval Process

The DG technologies considered for the City of Irvine were the gas reciprocating engine (engine) or the microturbine. Initially, approval procedures were sought for engines to be sited at a recreational center. Overall, the approval process and procedures with the City of Irvine are straightforward, instructions are relatively clear, and staff is helpful.

As a first step, the City of Irvine's Community Development group was contacted. The Community Development group includes the Department of Planning and Development Services (Planning Department) and Building and Safety (Building Department); both were contacted. The response time for both departments was a same-day response.[62] In the case of the Building Department, applications and plans for review are a "one-stop" process. Several sets of drawings, along with application forms and fees, must be submitted. The Building Department forwards the information to the respective City departments, e.g., building, planning and fire. The City provides forms that can be mailed (e.g., forms that must be completed in triplicate), as well as select forms in downloadable format from the City's website. The Planning and Building Departments each have a five-day target time frame for completing application review, however it was indicated that up to 20-days for review is not unusual. With respect to the Fire Department, up to 10-days for application review is typical.

The Planning Department initially reviewed the zoning classification of the proposed site and identified it as a 1.5 Recreation Zone; thus, the main planning issues for that site are setbacks and potential noise issues. With respect to contacting the local gas company regarding natural gas supply for the project, the City would address the issues rather than having the developer contact the local gas company. Based on an initial review of the zoning code provided by the City, there are no significant approval issues. With respect to air quality permitting, the City noted it is necessary to contact the SCAQMD directly.

The SCAQMD was contacted using the general "Permit Information" phone number provided by the City. The Duty Desk of the Neighborhood Commercial Operations Team was contacted, and a same-day response was also received.[63] The Duty Desk representative was helpful and responded to general questions regarding the air agency's process. The SCAQMD maintains all the necessary forms and instructions on its website, therefore the permit application process can be readily initiated. The forms must be completed and subsequently submitted to the SCAQMD in person or via mail; electronic form submittal is not an option at this time. The option for expedited permitting is available. An additional time and materials fee associated with the expedited permit review and approval must be provided. The microturbine (60 kW) is exempt from the SCAQMD permit process. Based on the understanding of the engine's emissions profile, the gas engine requires a permit, and it is expected that the proposed gas engine would meet the SCAQMD's BACT requirements. The only outstanding issue to be evaluated would be the health risk assessment and a determination that the risks are below the SCAQMD's risk thresholds for chronic and acute exposure of cancer and non-cancer combustion by-products.

Although specifics regarding the siting of a microturbine or multiple microturbines were not explicitly discussed with the City, the same type of review by the City's Community Development's departments is be expected. The same type of forms would be completed, and the review times would be similar. The main difference would be that an air permit is not required because the microturbines are below the SCAQMD's exemption level for gas turbines.

Highlights of Industrial Site Approval Process

The DG technology considered for Paramount, a small refinery in the City of Paramount, is a small industrial gas fired turbine (turbine). The proposed addition of the turbine is part of Paramount's "NOx Reduction Project." The addition of the turbine will be in conjunction with the shutdown of existing boilers. The site is currently an established, existing industrial facility. Paramount staff and management initiated the agency approval process. To address the environmental assessment and air agency requirements, Paramount has consulting support from firms that are knowledgeable about the agencies' respective approval requirements. Paramount's approach is similar to what is outlined in Figure 21. That is, Paramount conducted a feasibility assessment of DG options to meet its facility needs, and they initiated discussions with agencies prior to final project design and application submittals. The following approval process discussed below is based on discussions with in-house environmental personnel, with specific focus on the air permitting process.

For an existing industrial facility, such as Paramount, the addition of a new turbine requires modifying any existing facility-wide approvals, as well as undergoing review for the turbine and its incremental additional environmental impacts. Paramount is a RECLAIM facility and will have a facility-wide air permit (Title V) issued by the local air district, the SCAQMD. Additionally, Paramount has a conditional use permit (CUP), from the City of Paramount City. To address agency approval requirements, Paramount maintains its well-established and proactive working relationships with the approval agencies, as well as the community members. This includes discussions with agencies prior to submitting the needed information for agency review in order to address potential regulatory barriers and to understand current requirements. Furthermore, consulting support is relied upon to supplement in-house capabilities for air quality and other environmental assessment issues. Paramount indicated that, because of their preliminary evaluation and discussions with agencies for obtaining the necessary permits and approvals, the process has been relatively straightforward.

Paramount currently maintains a CUP and was issued a negative declaration for its development of reformulated gas in the mid-1990s. As a result of the proposed turbine addition, the requested assurances that conditions of the CUP are met and that additional aesthetic mitigation measures (e.g., architectural treatments) are in place. Initially, there were discussions about whether the City or the SCAQMD would serve as the lead agency. To date, it has been determined that the SCAQMD would serve as the lead agency. At this time, Paramount expects a negative declaration will be issued.

Paramount currently is awaiting a facility-wide Title V permit, which covers all polluting equipment at its facility. The addition of the turbine requires a local permit that specifies the necessary emission levels, record keeping, reporting, monitoring, and testing requirements. These conditions will be included in the facility's final Title V permit. It is not expected that the addition of the turbine will delay the Title V permit issuance. It should be noted that the turbine approval could proceed without the final Title V permit, at this time. Because the facility is a RECLAIM[64] facility and the turbine will be fired solely on natural gas, Paramount determined the level of additional NOx RECLAIM trading credits for the reduction project. Paramount also evaluated whether emission reduction credits would be needed for the other pollutants under the New Source Review (NSR) permit requirements. Due to the shutdown of the existing boilers, Paramount is taking "credit" for the shutdown emissions and applying them to the increases associated with the new turbine. This eliminates the need to purchase costly credits on the open market. To obtain these credits, Paramount quantified the actual reductions from the boilers and obtains SCAQMD approval. This included reviewing historical emissions data and negotiating acceptable emission factors for quantifying the creditable reductions.

Based on the SCAQMD's BACT guidelines,[65] the BACT emission levels for natural gas-fired gas turbines $\geq$ 3 MWe and < 50 MWe are as follows:

- NOx: (2.5 ppmvd @ 15% O2) * [efficiency (%)] / 34%
- CO: 10 ppmvd @ 15% O2
- Ammonia (NH3) slip: 5 ppmvd @ 15% O2

As noted in the cogeneration analysis report prepared by Dana Technologies, Inc. (Dana), the "top-down" NOx BACT emission level may be as low 2.5 ppm @ 15% O2 based on the requirements imposed on much larger combined cycle projects. However, most recently, Dana notes that a NOx level of 3.0 ppm was guaranteed for add-on SCR on a Solar Taurus turbine. Paramount has agreed to meet the SCAQMD's most recent BACT determinations noted above, with a potentially lower level for CO. The proposed control technologies include selective catalytic reduction (SCR) with an ammonia degradation catalyst to meet a NOx level of 2.5 ppm @ 15% O2 (1-hour averaging period) and an NH3 slip levels of 5 ppm @ 15 %O2.[66] The CO level will be either 4 ppm or 6 ppm (1-hour averaging period), depending on final negotiations with the SCAQMD.

For all DG projects that require an air permit, the SCAQMD must determine whether there is a school within 1,000 feet of the source. If a source is within 1,000 feet of a school, the state requires a 30-day public notification (of the proposed permit action) to a select population as follows:

- Parents of all students at schools within _-mile of the source
- Residents within 1,000 feet of the source
- Businesses within 1,000 feet of the source

Because there are schools adjacent to Paramount, Paramount evaluated several locations for the turbine. In addition to the criteria noted above, other considerations included existing infrastructure (e.g., natural gas pipeline, substation, steam lines, etc.) and impacts to residents (e.g., noise, aesthetics). After considering several alternatives, Paramount selected a location at the site where the facility perimeter is not within 1,000 feet of a school, thus eliminating the public notification requirement. It should also be noted that the SCAQMD concluded there is no significant public health impact from the turbine emissions.

Comparison of the Municipal and Industrial Cases

As previously described, similar steps are taken to contact agencies. Generally, it is the actual interaction between the project applicant and the reviewing agencies that determines how the approval will proceed. The objectives of contacting agencies are to identify the procedures for obtaining the necessary approvals and to meet agencies' requirements. In both cases, the project team did not undergo the actual process of agency interaction and acquiring approvals.

Although it may be characterized that the municipality case was less involved than the industrial case, the features of each project are not directly comparable. The similarities include compatibility with the current land use and zoning classification, the choice of natural gas fuel, and the same air agency jurisdiction. However, there are more differences in project features than similarities. The environmental impacts to the surrounding areas are different from a planning agency perspective. Different DG technologies were proposed, each resulting in different emission profiles and structural requirements. The site for the municipality is considered a relatively small and minor site. The existing, major industrial facility of the refinery has existing air polluting equipment and existing air permits. Although these differences exist, an evaluation of the process and potential hurdles in the approval process can be discussed given the framework of the Energy Commission's recent evaluation of CEQA review and permit streamlining.

Interacting with the Planning and Building Approval Organizations

The City of Irvine, as the DG project proponent, presents a relatively straightforward case for the potential ease of undergoing local permit processing. It can be anticipated that the City of Irvine would facilitate the interaction among departments, not only because of its "one-stop" process and objectives to streamline the process, but because there is a vested interest in the project.

Given the apparent simplicity of the City of Irvine's planning and building departments approval process based on the proposed DG project characteristics, another municipality process was sought in order to provide a contrasting example of a more involved effort. The County of Santa Barbara is relatively well known for its more involved. A DG project proponent would have to approach individual agencies rather than undergo a "one-stop" process as experienced with the City of Irvine. At a minimum, the individual agencies to be contacted would include the following:

- Santa Barbara County Air Pollution Control District
- County Building Department
- County Planning & Zoning
- County Fire Department
- County Environmental Health Services
- Southern California Gas Company

Similar to the City of Irvine, each agency has its own set of rules, permits, procedures, fees, and processing timelines. However, because there is not the "one-stop" process as established by the City of Irvine, the requirements of the separate agencies may be sometimes conflicting and require additional time to reconcile differences and ensure conformance with each agencies' requirements.

Another notable issue associated with the City of Irvine is the fact that the land use and zoning classification for the selected site can readily accommodate the proposed DG project; that is, the proposed use is consistent with the City's requirements. This factor alone, siting a project with compatible land use, is critical to a more expeditious approval process. Under different circumstances, if a DG project is not consistent with the existing allowable use, the process would be significantly more involved and include public review for amendments to zoning and land use plans. This may result not only in potential amendments to land use but mitigation of environmental impacts such as noise and aesthetics. For both the City of Irvine and Paramount, both projects avoided this potential obstacle of amendments to the zoning ordinances and land use plans. Finally, discretionary review of a DG project would result in additional time, agency review, increased processing costs. This adds to further uncertainty in the approval process.

For the building permit process, it is expected that the process should be similar among jurisdictions. There is not an explicit distinction inherent in the building permit approval process other than the land use and zoning issues addressed by the planning agency. The only potential issue that would be raised is if the local jurisdiction of the proposed DG project has amended the building codes to more stringent levels than the standard building codes; therefore, it would be expected that there would be differences in the required approval criteria. This type of difference is the reason why the Silicon Valley region instituted the Silicon Valley Uniform Code in order to minimize the differences in building permit requirements from jurisdiction to jurisdiction.

Interacting with the Air Agency

With respect to air quality, the air agency is the same. Therefore, the approval process is similar. However, as described in the previous sections, different DG technologies have different emission impacts. The additional level of complexity is primarily a result of meeting the BACT requirements. In the case of both scenarios, the proposed DG technologies meet the SCAQMD's BACT requirements. Meeting the air agency's BACT requirements greatly reduces the level of negotiations for permit approval. However, if a DG project did not meet the BACT requirements, a "top-down" BACT evaluation would be necessary. This would require a cost-effectiveness analysis that demonstrates additional controls to minimize emissions are not cost-effective. Under this circumstance, technical support information must be provided that justifies higher emission levels and potentially extensive negotiations with the air district.

From the perspective of a municipality proposed project and an industrial facility proposal, it is unclear what increased or decreased level of agency interaction would result. Air agency approval is typically DG technology and emissions specific. Because the municipality case is a "new source" versus the industrial case of an "existing, major source," the treatment of both applications at the air agency is expected to be different. Common air agency review elements for both projects include:

- Application forms, fees and support information,
- Proposed DG project operation emissions,

- Proposed control technology for BACT, if applicable, and
- Air toxic emissions and health risk assessment.

Additional information considered for the existing industrial facility air agency process is the following:

- Evaluation of compliance of existing operations with current permits,
- Revisions to an existing facility-wide permit or the need to include a DG source in a facility-wide permit application,
- Historical existing equipment emissions,
- Proposed overall DG project emissions, considering increases from the turbine emissions and any enforceable (permitted) decreases or shutdown of existing equipment (e.g., boilers), if applicable, and
- Air quality modeled impacts of NOx emissions, if applicable threshold is triggered.

The added information that must be provided by the industrial facility is relatively significant, particularly if other existing equipment is affected – whether by changes in its operations or the shutdown of its operations. The Paramount case exemplifies the need to consider existing permit conditions, emission reduction credits, air toxic emissions and public notification, and BACT requirements.

Potential Obstacles for DG Permitting

Based on the two cases considered, the potential obstacles for DG permitting remain the same obstacles as identified by the Energy Commission in its evaluation of the CEQA review, building permit and air permit streamlining process. Specifically, there is not uniformity and/or consistency among the different approval agencies within the same categorical areas. Planning departments will differ in their requirements because of local ordinances. Building departments will differ in their requirements because of amendments to building codes that may have been customized to meet the local jurisdictions' areas of concern. Air agencies will differ in their requirements, mainly emission level requirements, because of the stringency of rules based on meeting the federal and state ambient air quality standards.

Planning Department Approval Issues

As described in Section 3.0, Overview of the Approval Process, the main issue is whether an involved CEQA review would be required. Because a planning agency may not have the benefit of being familiar with the DG technology and its potential impacts, it is helpful to provide a project description that fulfills the agency's review criteria. In most cases, a DG project can be designed to meet the agency's requirements by either showing no significant impact or mitigating the environmental impacts. In order to minimize issues associated with the planning agency's review, a DG project should be sufficiently described in terms of the environmental impacts highlighted in Table 22, Planning Agency's Review Consideration for Environment Impacts. This would assist the planning agency review process. In each case, the planning agency must determine whether the DG project has one of the following environmental impacts:

- Potentially Significant Impact

- Less than Significant with Mitigation Incorporation
- Less than Significant Impact
- No Impact

A series of questions regarding each potential environmental impact must be answered to determine the level of impact. Table 22 highlights the type of information that should be provided for a DG project when presenting the project to the planning agency.

Table 22. Features of Project Description for Determining Environmental Impacts[(a)]

Environmental Impact	**Project Description**
Aesthetics	Visual characteristics; impacts on existing area; impact on scenic vista or resources; potential new source of light or glare that would affect day or nighttime views.
Agriculture Resources	Impact on farmland; conflict with zoning for agricultural use.
Air Quality	Impact on air quality plan; violations of standards or contribution to a violation; cumulative net increase in emissions; pollutant exposure level on sensitive receptors; odors.
Biological Resources	Impact on habitat (e.g., candidate, sensitive species); impact on wetlands; impact on native or migratory fish or wildlife species; conflict with ordinances protecting biological resources; conflict with conservation plans.
Cultural Resources	Impact on historical, archaeological or paleontological resources; impact on human remains (e.g., cemeteries).
Geology / Soils	Seismic zone concerns; potential for ground failures; possible soil erosion or topsoil loss; location in unstable area (e.g., potential for landslide, liquefaction, etc.); soil stability issues.
Hazards and Hazardous Materials	Risks from hazardous materials transport, use or disposal; accidental release; hazardous-related emissions within _-mile of existing or proposed school; location on an existing site with hazardous materials issues; location nearby an airfield; interference with emergency response/evacuation; exposure to populated areas or wild lands.
Hydrology and Water Quality	Impact on water quality or waste discharge standards; groundwater depletion potential; alteration of existing drainage pattern; contribution to runoff water and storm water; 100 year flood hazard area consideration; flooding potential.

Table 22. Features of Project Description for Determining Environmental Impacts[(a)] (cont.)

Environmental Impact	Project Description
Land Use / Planning	Impact on established community; conflict with land use plan, policy, or regulation; conflict with habitat conservation plan or natural community conservation plan.
Mineral Resources	Impact on known mineral resources locally, in the region, or in the state.
Noise	Noise level impacts on population in the project vicinity; ground vibration impacts; impacts to residents or businesses if nearby an airfield.
Population / Housing	Population growth effects; displacement of housing or people.
Public Services	Impact on governmental facilities; impact on public services including fire protection, police protection, schools, parks, other public facilities.
Recreation	Impact on existing public parks and recreational facilities; project includes recreational facility.
Transportation / Traffic	Impact on existing traffic (e.g., capacity, traffic patterns); cumulative impact regarding congestion; safety issues; effect on emergency access, parking; impact on alternative transportation.
Utilities and Service Systems	Impact on existing wastewater burden, storm water drainage facilities, water supplies, landfill, and solid waste; conformance with solid waste requirements.

NOTE: (a) Based on CEQA guidelines and sample environmental checklist form.

In many cases, relatively small and DG projects within structures would have less than significant or no impact for several environmental issues. The environmental impacts that are likely to be raised for DG projects include the following:

- Aesthetics (particularly for projects in public view),
- Air quality (e.g., pollutant emissions),
- Hazards and hazardous materials (e.g., equipment chemicals, ammonia if certain control technologies are used to minimize pollutant emissions), and
- Noise (e.g., decibel level of equipment operations).

Therefore, to the extent that the DG project proponent comprehensively describes the project within the context of the above criteria and specifically references or uses the environmental checklist that the planning agency uses, a more streamlined review by the planning agency can be expected.

Building Department Approval Issues

As described in the previous sections addressing building department issues, project engineering design and construction must be reviewed for conformance with relevant local, state and national building codes. Permit applications must be submitted, plans are reviewed and approved, and site inspections are performed to ensure conformance with the codes. There are several forms that must be submitted with the relevant support documents. Each jurisdiction has its prescribed building codes that may be based on model codes developed by national organizations or that may be based on state codes, e.g., building, fire, mechanical, plumbing, and fire codes.

With respect to the two DG project cases; a limited evaluation of issues is available. Although the City staff was helpful and provided information, without actually submitting building permit applications and construction drawings, and undergoing agency review, streamlining issues associated with the approval process can not be identified at this time. In the case of the industrial facility, no major issues were identified. Therefore, the discussion for building permit approval streamlining is based on information from the foundation of the SVUC Program, from the Energy Commission streamlining report, as well as other experience in DG project siting.

The approval process itself is relatively straightforward; however, the building codes and the interpretation of the building codes that serve as the basis for review present some issues. One of the issues identified by the Energy Commission is that jurisdictions may not be aware of the California Building Standards Code. These state codes are based on the model codes developed by national organizations. Local jurisdictions are responsible for ensuring that the state codes are being met and enforced; however, some local jurisdictions may have adopted the national model codes directly rather than enforcing the state codes. In doing so, amendments to the model codes may have been adopted, and it is conceivable that local jurisdiction amendments may differ and even conflict with state codes.

Approval agencies and developers have recognized inconsistencies associated with the building permit process. As an example of addressing these issues, the Energy Commission highlighted in its DG streamlining document the efforts initiated by the Joint Venture Silicon Valley network and other regional stakeholder in that area. The SVUC Program was developed to provide consistency of the code requirements among the jurisdictions, as well as streamline the approval process.

One other notable element of the building department approval process is the fire department review and approval. In virtually all jurisdictions, the fire marshal has the responsibility for the final determination of compliance with the fire code. Therefore, it is conceivable that even upon obtaining approvals from the building department for the numerous construction requirements, the fire department may raise code conformance issues. Although a building department may lead the coordinated effort for approval by the fire department, it is important to note that approval for fire code related issues will also be addressed.

Air District Approval Issues

There are explicit air permit exemption thresholds and thresholds stipulating the need for an air permit. For DG projects, with the exception of non-polluting equipment and relatively small DG technologies (e.g., microturbines, fuel cells), fossil fuel-fired technologies such as reciprocating engines and turbines must obtain an air permit.

Because of the multiple air agency jurisdictions throughout California, like the planning and building department processes, regulations differ from region to region. All districts require the same type of information, however, differences from agency to agency include:

- Application forms and fees,
- Title V permit program implementation
- Details of support information that must be provided,
- Emission factors to estimate air toxics, and
- BACT requirements and pollutant-specific cost-effectiveness benchmarks (if applicable).

Application forms and fees differ in terms of level of detail and cost for review. Depending on the agency and/or DG technology, fees may be fixed fee or on a time and materials basis. As noted in the case of SCAQMD's jurisdiction, a time and materials fee can be assigned for expedited permit application review. For all DG projects, emissions must be estimated, exhaust gas parameters must be defined (for air toxics evaluation), and a demonstration of compliance with rule requirements must be made. Project location and site maps must also be provided in order to confirm whether a school is within 1,000 feet of the proposed DG project.

If a facility has an existing Title V operating permit, the DG project must be included in this permit. Therefore, a modification of the operating permit is necessary. For many agencies, separate Title V application forms and fees apply. Additionally, there are separate review and processing times. Both local and federal regulatory requirements must be identified. Depending on the emission levels, a public comment period may be necessary. For permit exempt DG sources, a minor modification may be obtained, thus avoiding a more rigorous review and public comment.

Criteria pollutant emission factors may differ from agency to agency. For most DG technologies, factors provided by the vendor and/or source test results of similar technologies are relied upon as the most representative, while default emission factors are used in absence of vendor information. If this is the case, it would be necessary for a developer to determine whether he/she is in agreement with the air agency's default factor. An example of this issue arose in Paramount's negotiations regarding its creditable boiler emission reductions. To resolve this issue, Paramount and SCAQMD negotiated acceptable boiler emission factors.

Air agencies may also have different criteria and air toxic emission factors and risk factors. In California, agencies use risk factors provided by the California Office of Environmental Health Hazard Assessment (OEHHA).[67] However, California air agencies may have different air toxic emission factors. The project team surveyed gas engine air toxic emission factors in four air districts – the BAAQMD, SCAQMD, SDAPCD and the Ventura County APCD (VCAPCD). Until early 2001, both the SCAQMD and VCAPCD prescribed air toxic emission factors based on a pool of source test data collected as a result of the state's air toxics program. However, the federal U.S. Environmental Protection Agency (EPA) issued factors that differ from these agencies' factors. Some factors are higher while others are lower. Consequently, for a gas engine project undergoing permit review and therefore an evaluation of health risk impacts, the same type of project in one jurisdiction could have a much higher impact if sited in another jurisdiction. Since the summer of 2001, the four agencies are now considering the use of the EPA factors.

BACT requirements are the most notable difference for air agency approval of a DG project, particularly for NOx emissions. The NOx level is based on some controlled level of emissions and therefore may require add-on control technology. As presented in Table 23, several control technologies (or a combination of controls) must be considered, and in conjunction, certain emission levels and/or certain control efficiencies must be met. Because many air agencies throughout the state have a BACT threshold of 10 lbs/day, most DG projects are required to demonstrate that the NOx emissions meet the agencies' BACT level.

For some agencies, a cost-effectiveness benchmark is provided to determine whether a control is applicable. That is, an agency may have a threshold for $ per ton ($/ton) of NOx emissions reduced. If a control technology is determined to be below the $/ton benchmark, the control technology is considered cost-effective and must be installed. Conversely, if the cost-effectiveness exceeds the benchmark, it is not necessary to consider the technology. Agencies differ in their cost-effectiveness benchmark and the level of detail to demonstrate BACT. Also, some agencies effectively require the lowest achievable emission rate (LAER), which does not necessarily consider cost-effectiveness. Examples of cost-effectiveness benchmarks for NOx include the following:

- Bay Area Air Quality Management District (BAAQMD) = $17,500/ton
- Kern County Air Pollution Control District (KCAPCD) = $10,000/ton
- Sacramento Metropolitan Air Quality Management District (SMAQMD) = $24,500/ton
- San Diego Air Pollution Control District (SDAPCD) = $18,000/ton
- Santa Barbara County Air Pollution Control District (SBCAPCD) = $20,000 - $30,000/ton

With respect to BACT for DG technologies, CARB has issued a draft[68] of "Guidance for Permitting of Electrical Generation Technologies" (September 2001). As presented in the introduction to this guidance document, CARB highlights the following:

> Senate Bill (SB) 1298 (Bowen and Peace), which was chaptered on September 27, 2000, required the Air Resources Board (ARB) to issue guidance to districts on the permitting or certification of electrical generation technologies under the district's regulatory jurisdiction. The statue also directs ARB to adopt a certification program and uniform emission standards for electrical generation technologies that are exempt from air pollution control or air quality management districts' (districts) permitting requirements. The proposed certification program is discussed in the ARB report: Proposed Regulation to Establish a Distributed Generation Certification Program, September 2001.

> SB 1298 specifies that the guidelines address Best Available Control Technology (BACT) determinations for electrical generation technologies and, by the earliest practical date, shall make the determinations equivalent to the level determined by the ARB to be BACT for permitted central station power plants in California. Finally, this guidance is to address methods for streamlining the permitting and approval of electrical generation units, including the potential for pre-certification of one or more types of electrical generation technologies.

Furthermore, the overview for this guidance document states:

> This report provides guidance to local air pollution control districts and air quality management districts (districts) regarding the permitting of electrical generation technologies. In particular, this report describes DG technologies; discusses existing regulations; addresses best available control technology (BACT) determinations; recommended emission levels for oxides of nitrogen (NOx), volatile organic compounds (VOC), carbon monoxide (CO), and particulate matter (PM); discusses how electrical generation technologies can achieve central station power plant levels; other permitting considerations including testing and monitoring requirements and the inclusion of a CHP credit; and methods to streamline the permitting of electrical generation projects under the regulatory jurisdiction of districts.

This guidance includes BACT levels (for NOx, VOC, CO) in lbs/MW-hr, and for PM emissions (natural gas) for gas turbines and reciprocating engines for electrical generation, with other considerations for combined heat and power DG applications. This guidance is expected to be used by California air agencies when reviewing and approving permit applications.

Other Agency Approval Issues

As previously mentioned, depending on the size and type of the DG source, other necessary approvals can include obtaining permits from local agencies such as the following: environmental/health department, public works, regional water quality control board, fire department, and water/wastewater district. For example, the storage, use or transport of hazardous materials or generation of waste requires approval by the local health department or delegated agency. Water and sewer discharges, if applicable, must also be approved. In many cases, these approvals must be obtained prior to operating the DG source. Therefore, it is necessary to ensure that all agency requirements and project approval milestones are defined to avoid project start-up delays. This is important if agency approvals are interdependent, e.g., an approval must be obtained from one agency before another agency can issue its approval.

Because forms, applications and procedures differ, relying on other jurisdictions information is in appropriate. Each jurisdiction must be approached for their applicable paper work and approval criteria. Therefore, pre-application meetings with respective agencies should be held in order to minimize delays in application processing. An effective method to streamline this process is to identify a single-point-of-contact for each agency. This can minimize uncertainty and allows the developer to rely on accountable agency representatives.

Local Community and Public Involvement Consideration

Planning and air agencies' actions may require public comment. Public comment periods are typically 30-days. Concerns raised by the public must be addressed prior to final approval. Based on discussions with Paramount and other DG project developers, public outreach is an effective means to reduce real and perceptive project impacts. This may include focus groups or meetings with community members, as well as political and governmental entities.

Permit Streamlining Recommendations

Based on the two case studies and experiences shared by DG project developers, Table 23 presents several recommendations that can contribute to the streamlining of the DG project approval process.

Table 23. Recommendations for Streamlining the DG Project Approval Process

General Streamlining	
Applicability	• Provide guidance regarding the level of review expected for various DG technologies, e.g., photovoltaics, fuel cells, wind energy, microturbines and small industrial turbines, and internal combustions engines. •
Community Groups	• Identify community groups that may be involved in a public comment process to facilitate outreach efforts. •
Cross-Cutting Issues	• Provide list of local agencies responsible for reviewing and approving DG project development. • Provide resource that identifies interdependencies of agency approval processes. •
Expedited Review	• Provide option for the conduct of an expedited application review process and approvals. • Develop certification process for DG technologies. •
Web-Based Resources	• Provide web-based resources regarding agency review guidelines, contact persons, time frames and application criteria. • Provide application forms and filing fee information. • Provide samples of DG technology project development that has successfully obtained agency approval. • Provide central-point-of-contact for agency review.

Table 23. Recommendations for Streamlining the DG Project Approval Process (continued)

Planning Department / Agency Approval Process	
Environmental Impacts	• Develop DG technology profiles that provide basic information of environmental impacts. • Use the planning agency environmental checklist to develop expected environmental impacts. • Characterize thresholds of significance for key environmental impacts. • Identify standard mitigation measures for DG technology profiles.
Land Use Plans and Zoning Ordinances	• Provide summary of the compatibility of DG project siting within the context of agencies' land use plans and zoning ordinances.
Building Department / Agency Approval Process	
Applicable Codes and Standards	• Develop summary of applicable building codes and standards for DG technologies. • Consolidate codes and standards for consistency with the California Building Codes, as well as Uniform Building Codes.
Fire Marshal	• Develop summary of applicable fire codes and standards for DG technologies. • Consolidate codes and standards for consistency with the California Fire codes, as well as Uniform Fire Codes.
Air Agency Approval Process[a]	
Applicability	• Define requirements for equipment certification and permitting based on local process and upcoming CARB SB 1298 guidance.
Application Forms	• Provide standard application forms (similar to forms standardized for portable equipment) for DG technologies undergoing permit review.
BACT Guidance	• Provide agency and statewide BACT guidance for DG technologies.
Emission Factors Guidance	• Provide emission factor resources for DG technologies. • Provide standardized emission factors for DG technologies.
Public Notification	• Provide guidance on preparing public notification for DG projects located within 1,000 feet of a school.
Processing Fee	• Provide for discount in agency processing fee when siting multiple, identical engines at a customer site.
Source Testing	• Provide standard requirements for source testing (e.g., pollutant types, acceptable test methods). • Provide streamlined source testing, e.g., pooled tests, pre-certified.

Note: (a) Potential project cost reductions associated with air quality compliance demonstrations and management have not been evaluated. For example, the acceptance of parametric emissions monitoring would eliminate costs (e.g., equipment, testing, maintenance, reporting) associated with continuous emissions monitoring system. However, potential cost reductions focused on the permit approval processes needed for construction and commencement of commercial operations.

The most notable recommendation is the development of resources that would provide up-front guidance for submitting the necessary paper work, while properly characterizing DG projects within the context of an agency's approval criteria. Benefits of each of the main recommendations are highlighted below.

- **General Streamlining** – Each recommendation can minimize the iterative process between agency and developer. Complete applications can be developed that meet agencies' approval criteria. Public outreach efforts, if necessary, can be established in the planning process. Understanding all the agency approvals that are necessary for construction and operation can eliminate potential scheduling issues.

- **Planning Department / Agency Approval Process** – These recommendations can contribute to a developer's site selection process. Project alternatives can be readily identified, particularly with respect to determining whether plan or zoning amendments are necessary.

- **Building Department / Agency Approval Process** – These recommendations can contribute to a developer's ability to ensure conformance with codes and standards that may not otherwise be considered in the initial engineering design phase.

- **Air Agency Approval Process** – These recommendations can contribute to a developer's ability to define a project that can be readily approved by the air agency. For issues where the developer may deviate from an agency's guidance, the developer can prepare justification for such deviations as part of negotiations with the air agency.

These recommendations are intended to provide more certainty in the approval process for the agencies and developers seeking project approval. This would facilitate discussions between the agencies and developers by minimizing the "guess-work" historically found in many development projects.

Cost Impact Estimate of Streamlined Siting and Permitting for the Two Case Studies

Several of the recommended streamlining opportunities could effectively reduce agency review time, as well as application preparation time by the developer. The estimate of the cost impact of streamlined siting and permitting is assumed to be the difference between the current cost estimates and the potential cost reduction by implementing recommendations in Table 24 that could directly reduce costs to the project developer. Project developer costs include fixed and variable costs. Fixed costs can include application-filing fees that are irrespective of equipment type or capacity. For example, application fees for submittal of equipment drawings (e.g., by building, planning and fire departments) are typically considered a fixed cost. However, these same agencies typically include a rate for "time and materials" (T&M) when reviewing more complex projects, thus a portion of the agencies' fees would also be considered variable costs.

Variable costs are those that are dependent on equipment type or capacity, as well as site conditions. For example, larger DG units at industrial facilities typically require more review time, and some sites may require a conditional use permit from the planning agency. Likewise, some air agencies' fees are based on size.[69]
The current cost estimates for siting and permitting of the two case studies includes agency review fees, developer's project management efforts, and outside consulting support for specialty areas. These current estimated costs for permitting are as follows:

- Municipality
  - Microturbine (60 kW) - $2,000[70] (or $33/kW)
  - Small gas engine (100 kW) - $8,000 to $15,000[71] (or $80/kW to $150/kW)
- Existing Industrial Source
  - Small gas turbine (6,452 kW) - $50,000[72] (or $8/kW)

Based on a qualitative assessment of the streamlining recommendations presented in Table 24, the recommended efforts that could directly reduce costs to a project developer include the following presented in Table 24.

Table 24. Potential Cost Reduction Opportunities from Streamlining

Streamlining Recommendation	Cost Reduction Opportunity
General - Develop certification process for DG technologies.	Certification could minimize or eliminate developer time for preparing application forms, as well as reduce agency application processing and approval time.
Planning - Use the planning agency environmental checklist to develop expected environmental impacts.	Availability of such a checklist could minimize developer time for preparing application submittal package, as well as reduce agency application processing time.
Planning - Provide summary of the compatibility of DG project siting within the context of agencies' land use plans and zoning ordinances.	Availability of this type of information could ensure that land use compatibility is addressed in the site selection process and therefore minimize or eliminate the need to undergo land use plan or zoning amendments.
Building – Consolidate codes and standards for consistency with the California Building and Fire Codes, as well as Uniform Building and Fire Codes.	Streamlining of codes minimizes the potential for conflicting or confusing requirements by standardizing and promoting consistency across jurisdictions. Cost reductions include minimizing developer's project re-design, as well as reducing agency application processing and approval time.

Table 24. Potential Cost Reduction Opportunities from Streamlining (continued)

Air Quality - Provide for discount in agency processing fee when siting multiple, identical engines at a customer site and/or air agency jurisdiction.	Discounting of fees has immediate cost reduction benefits to the developer. Rather than charge for "per DG unit" evaluation, economies of scale would be realized by charging less for identical engines.
Air Quality – Provide streamlined source testing, e.g., pooled tests, pre-certified.	Pooled source tests or pre-certified equipment would minimize or eliminate the need to conduct tests on identical engines (e.g., same make, model) by relying on past performance of other engines that have been tested.

Based on the case studies discussed in this report and the potential cost reduction opportunities presented in Table 25, the estimated costs for streamlining are as follows in Table 25.

Table 25. Estimate Of Cost Savings For Two Case Studies From Streamlining

Case	Current Permit	Cost Reduced	Streamline Permit	Cost Savings
Microturbine	$2,000	(a)	(a)	(a)
Small Gas Engine	$15,000	$6,000 (b)	$9,000	$60/kW
Gas Turbine	$50,000	$10,000 (c)	$40,000	$1.5/kW

Note:

(a) Assumes that the permit costs for a microturbine would remain the relatively the same because of the current straightforward approval process and of the future statewide certification program.

(b) Assumes cost reductions for developer preparation of applications to agencies and elimination of or reduction in source testing requirements.

(c) Assumes cost reductions for developer preparation of applications to agencies and elimination of or reductions in source testing requirement.

Therefore, the streamlined cost estimates for siting and permitting of the two case studies are as follows:

- <u>Municipality</u>
  - <u>Microturbine (60 kW) - $2,000[73] (or $33/kW)</u>
  - <u>Small gas engine (100 kW) - $9,000 (or $90/kW)</u>
- <u>Existing Industrial Source</u>
  - <u>Small gas turbine (6,452 kW) - $40,000 (or $6.2/kW)</u>

Estimate of Cost Savings for Streamlining for DG Statewide

The estimate of the cost savings for streamlined permitting is based on the two case studies previously discussed and the high market penetration case for CHP presented in the September 1999 report titled "*Market Assessment of Combined Heat and Power in the State of California*."[74] As part of the 1999 market assessment effort, a market penetration forecast (through 2017) was developed based on a CHP economic analysis, the market potential (e.g., California industrial and commercial market sectors), and the historical rate of market penetration by size and market for CHP. For the cumulative penetration levels, its was assumed that the current potential grows at 2% per year over the forecast period.

The high market penetration case assumed improvements in CHP technology performance and package costs, cost reduction impacts of CHP initiatives, and improved rates of market response. For CHP projects under 1 MW, it was assumed that the market penetration rates (given no change in the internal rate of return, IRR) would increase exponentially over the forecast period to a level 200 times the historical rate by year 2017. For the 1-5 MW size range, the factor is 50. For the 5-20 MW class, the factor is 5. For the 20-50 MW size, the factor is 1.5. The results of the high market penetration case are summarized below in Table 26.

Table 26. High Market Scenario For CHP Penetration[A]

CHP Category by Size	Cumulative Penetration in MW	Cumulative Penetration in Units
50 - 250 kW	389.9	3,904
250 – 1,000 kW	568.9	1,031
1 – 5 MW	793.7	331
5 – 20 MW	1,319.7	148
> 20 MW	5,816.5	75

Note: (a) Excerpt from September 1999 market assessment report (Table 3-3.7)

Based on cost savings previously highlighted for the two case studies and on the cumulative penetration in MW of the various CHP categories, Table 27 presents the potential approximate cost savings of streamlining for DG statewide.

Table 27. Approximate Cost Savings Of Streamlining For DG Statewide

CHP Category by Size	Statewide Cost Savings
50 - 250 kW	$23,394,000 [a]
250 – 1,000 kW	$34,134,000 [a]
1 – 5 MW	$1,190,550 [b]
5 – 20 MW	$1,979,550 [b]
> 20 MW	$8,724,750 [b]
Estimated Total:	$69,422,850

Note:

(a) Based on cost savings of $60/kW.
(b) Based on cost savings of $1.5/kW.

Conclusions for Potential Cost Savings from Permit Streamlining

As a result of implementing various streamlining recommendations that provide up-front guidance for submitting the necessary paper work, that reduce costs based on identical DG equipment, and that minimize or eliminate the costs associated with DG emissions testing, nearly $57.5 million (over the next 15 years) may be saved statewide for CHP applications that are less than 1 MW. Likewise, for applications 1 MW and greater to under 50 MW, nearly $11.9 million may be saved statewide. It should be noted, however, that these are rough estimates based on the qualitative assessments of streamlining opportunities for the two case studies presented in this report. Other considerations that can affect the magnitude of the potential cost savings include the following:

- **DG Market Penetration May Differ** – The estimate of cost savings over the next 15 years is based on a market penetration case that considers various economic factors (e.g., electric rates, gas rates, internal rate of return), improvements in DG technologies, and the implementation of CHP initiatives (e.g., standardization, streamlining, incentives). Changes in these assumptions will directly affect the potential cost savings that can be realized. Additional evaluation would be necessary to identify specific regional cost saving benefits

- **Local Agency Review May Differ** – Project costs are directly related to the local agencies' requirements for the chosen DG project site and technology. At a minimum, agencies have different fee schedules and procedural requirements. Therefore, the cost savings that may result from the statewide implementation of recommended streamlining opportunities are expected to differ from county to county. That is, if the same identical DG project (e.g., equipment type, size, operations, land use) located in Los Angeles City is also located in Sacramento, the cost savings at each site is likely to be different for a given streamlining measure. In order to assess the cost-effectiveness of a streamlining opportunity at the agency level and on a developer, it would be necessary to implement the same program and conduct a comparison of the actual cost impacts for both fixed and variable costs.

- **Streamlining Opportunities Must be Prioritized** – In order to facilitate the deployment of DG technologies and to minimize the obstacles in the permit process, streamlining opportunities should be prioritized based on projected costs for its design and implementation, potential ease of agency acceptance and standardization among the different jurisdictions, and estimated cost-savings to the project developer.

SUMMARY OR ABBREVIATIONS AND ACRONYMS

A – J	
ARB	Air Resources Board
BAAQMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
CARB	California Air Resource Board
ENERGY COMMISSION	California Energy Commission
CEQA	California Environmental Quality Act
CHP	Combined Heat and Power
CO	Carbon Monoxide
CUP	Conditional Use Permit
DG	Distributed Generation
EIR	Environmental Impact Review
EPA	U.S. Environmental Protection Agency
ERCs	Emission Reduction Credits
IRR	Internal Rate of Return
JVSV	Joint Venture Silicon Valley

K – T	
KCAPCD	Kern County Air Pollution Control District
KW	Kilowatt
LAER	Lowest Achievable Emission Rate
MW	Megawatt
NH3	Ammonia
NOx	Oxides of Nitrogen
NSR	New Source Review
O2	Oxygen
OEHHA	Office of Environmental Health Hazards Assessment
PM	Particulate Matter
PV	Photovoltaic
RECLAIM	Regional Clean Air Incentives Market
RTC	RECLAIM Trading Credit
SB	Senate Bill
SBCAPCD	Santa Barbara County Air Pollution Control District
SCAQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction
SDAPCD	San Diego Air Pollution Control District
SMAQMD	Sacramento Metropolitan Air Quality Management District
SVUC	Silicon Valley Uniform Code
T&M	Time and Materials

U - Z	
VCAPCD	Ventura County Air Pollution Control District
VOC	Volatile Organic Compounds

Transmission System Services Provided by Distribution Level Distributed Generation

Introduction

Many studies, reports and industry experts in the field of distributed generation (DG)[75] broadly refer to the benefits that DG can provide to transmission and distribution systems. This report provides a qualitative analysis of the issues that drive the impacts and benefits DG on the transmission system. A companion study to this report identifies the services that DG can provide to distribution systems.[76] The objective of this report is to identify transmission services that DG is technically capable of providing, and to develop guidelines that will enable DG to participate in markets for these services given the technical and operational requirements of the system.

The amount of generation relative to the system total load, or penetration, is the most important factor for the influence of DG on transmission operation. A single 2 MW generator may have considerable impact on the operation of a distribution system, while going wholly unnoticed on the transmission system.[77] On the other end of the spectrum, if a fully mature DG market results in 30% or more of the total customer load supply, the impact and importance to transmission operation will be undeniable. A tougher question is what the impacts are at penetration levels between the two extremes, and how they should be treated with respect to considerations of both system control and economic valuation. This question is addressed by focusing on both the localized transmission benefits that a relatively small penetration of well-sited DG can provide, and the benefits to the larger transmission system as a whole that can feasibly be achieved by growing DG penetrations.

FERC Order 888[78] established the definitions for generation related ancillary services for bulk transmission, and these definitions have been adopted throughout North American power markets. The California Independent System Operator (ISO) purchases and provides the ancillary services that are required for bulk transmission transactions in California, including specifying technical and operational requirements for the generators that provide those services. This report discusses the transmission benefits of DG in the context of California markets, and hence focuses on the ancillary service definitions and practices in use, and proposed for, the California market. In addition to discussing the capability of DG to provide ancillary services, this report identifies additional transmission related benefits that can be provided by DG, and concludes with a discussion of issues that will impact the degree to which DG can penetrate each of these transmission services markets.

The remainder of this report is organized into three major sections:

4) An overview of transmission level services that can be provided by distribution interconnected DG;
5) Detail descriptions of DG transmission services; and
6) Guidelines for DG participation and penetration.

Overview of DG Transmission System Services

The electric grid is a massive interconnected network of large and small generators, transmission and distribution lines, and customer loads. Power from larger central generators is converted to high power or bulk transmission voltages typically ranging from 110 kilovolt (kV) to 765 kV for delivery over long distances to local area load centers. This power may then be converted to sub transmission levels (23 kV-138 kV) for delivery to distribution substations and large industrial customers. Distribution substations located within these load centers convert the transmission voltages to lower voltages, generally 35 kV or less. Power lines emanating from distribution substations course through population areas serving residential and commercial customers.[79]

Generators over 10 MW in size are almost always interconnected at the sub transmission or transmission system level due to the relatively limited power carrying capabilities of distribution system. Depending on their size and location, these generators play an important role in the operation of the transmission grid, both at the local level (around load centers) and among the bulk system lines that link to other load centers and central generators. Smaller distributed generation located on the distribution system has to date had little impact on the transmission system operation, but this will change as their penetration grows. With sufficient capacity levels, DG sited on the distribution system will be able to provide beneficial services to the sub transmission and transmission systems. These services can be roughly divided into two categories: 1) services providing localized capacity benefits for area-specific networks, benefits which have a direct consequence for the local utility wires company; and 2) services that affect the larger bulk transmission system as a whole, typically defined by the independent system operator (ISO) as Ancillary Services. The remainder of this section provides a high level summary of these two classes of DG services.

Localized Impact of DG on the Transmission System

Studies for more than a decade have enumerated the economic benefits that DG can provide utilities as a means of justifying project costs. Most of these studies focus on the larger avoided costs associated with the deferral of new distribution capacity expansion projects. These projects involve the installation of new substations, construction of feeders, acquisition of land and right-of-ways, and miles of conductor and cable. The value of avoiding or deferring such investments may not be sufficient to fully pay for an alternate DG installation. DG studies that demonstrate the highest economic benefit usually include, in addition to these cost savings, the ability to defer still larger investments in transmission infrastructure. Transmission capital and installation costs are significantly higher than distribution (e.g. on a per mile basis). Utilities facing costly and controversial transmission upgrades could realize substantial savings if well-placed DG can defer or minimize such projects by providing transmission system benefits.

Benefits to the transmission system include the following technical benefits, many of which are analogous to those provided by DG to distribution systems.

- Capacity benefits - The prevention of excessive currents and overloads during peak loading periods given normal conditions (all major components in service).

- Contingency capacity - The prevention of excessive currents and overloads during peak loading periods given emergency or contingency conditions (one or more major components out of service).

- Voltage support - The prevention of excessive voltage drop during peak load periods, both under normal and contingency conditions.

- Power flow balance - The ability to alter the flow patterns on a multi-path system experiencing congestion problems.

- Loss reduction - The reduction of currents and losses on conductors and transformers that results when DG provides an alternate, local supply for area loads.

- Equipment life extension - The deferral of facility replacement projects that may be justifiable if DG reduces loading on older equipment to levels below an appropriate de-rated value.

Transmission Ancillary Services

Bulk system ancillary services (A/S) are a group of well-defined services currently provided by generators located on the transmission system, and bought and sold on the market through the ISO. The following is a brief summary of these services and DG's potential for participation.

- AGC/ Regulation - The generator provides system regulation service by adjusting output and voltage as necessary to maintain stability.

- Spinning Reserve - The generator provides a quantity of unloaded capacity synchronized to the grid that will ramp up within 10 minutes.

- Non-Spinning Reserve - The generator provides a quantity of capacity that is not synchronized to the grid but can ramp up within 10 minutes.

- Replacement Reserve - The generator provides a quantity of capacity that will ramp up within 60 minutes.

- Reactive Power/ Voltage - Generators maintain localized voltage within ISO tariff specified power factor range.

- Black Start - Generators supply power to de-energized portions of the grid as part of an orderly power restoration process.

Given sufficient penetration and control as described later in this report, distribution level DG can reasonably provide each of the reserve services (spinning, non-spinning and replacement) by quickly reducing the loading needs of area substations and by extension the bulk transmission. From the ISO perspective, the generation may be little more than a demand reduction device, but by definition it will be dependent on that reduction if the

DG unit is to qualify as a reserve service provider. Relatively high penetrations of particular types of DG can also conceivably provide reactive power and bulk system voltage support, by modifying the power factor of the substation loads.

The usefulness of distribution level DG for regulation and black start applications is minimal in the current context of grid operations. However, future scenarios with significantly higher levels of DG penetration (e.g., greater than 15-20%) do allow for DG to play a limited role. Large aggregations of such DG under control of an ISO could conceivably be controlled to ramp or reduce flows to counter fluctuations on the bulk system. Providing black start services with DG may be the least technically feasible because of DG's limited capability to energize sections of the transmission grid. DG could provide them indirectly by creating small islands, and therefore reduce the initial reinitiating of load requirements of system level generators.

The following sections provide a more detailed description and discussion of the services that DG can provide to transmission systems.

Detailed Transmission Service Definitions- Localized Impacts

Capacity Support

DG can provide capacity support at various levels of the transmission system by reducing the amount of load that would ordinarily be supplied by the utility. Power supplied by the generator to local loads on the distribution system reduces the net load seen by the utility. If the transmission or sub transmission lines feeding the distribution substations are operating near their maximum current ratings, the presence of properly sized DG can help to insure that these ratings are not exceeded. Expansion plans based on existing operating conditions and forecasted load growth may be deferred with DG.

The ultimate economic benefit of capacity support is the deferral or avoidance of capacity upgrades that are needed to provide reliable service to customers under normal peak load conditions. The facilities deferred may be limited to upgraded conductors serving an existing substation, or may involve entire substation facilities with transformers, breakers, capacitors, switches, and additional feed lines from the transmission system. Generally, the greater the deferral benefit, the greater the required DG size. As mentioned in the introduction, using DG for capacity support at both the transmission and distribution levels is widely acknowledged to provide the greatest wires-related economic benefit from siting DG.

The economic benefits of capacity support are straightforward to analyze in a particular project because it is applied directly to deferral of well-understood capital expenditures.[80] While the costs and benefits from one project to the next may vary significantly, an example of the economic value can be derived from generalized estimates of transmission equipment capital costs. Transmission facility costs are typically in the range of $100 to $200 per kilowatt (kW) of installed capacity in the range of 100 to 1000 MW, depending on voltage level and distance. Some of the less expensive DG technologies installed on the distribution system may cost anywhere from $350 to $500 per kW. If $100/kW is assumed for transmission facilities, and $500/kW is assumed for DG, then an example project to add 100 MW of new power delivery capacity would require either a $10M transmission expansion or $50M of DG dispersed in the area. The deferral of the transmission in this case may not alone justify the cost of the DG, but capturing this benefit on top of customer-specific or other local economic benefits could very well provide additional incentive for both the customer and utility.

Proponents of DG point to additional benefits of using DG for local capacity, above and beyond the economic value associated with avoided costs.[81] One of these benefits is the reduced risk of over-investment in major facilities if there are uncertainties in the load growth projections. Buying incremental capacity with DG buys additional time to observe the actual growth in load. If growth falls short of original expectations, the utility will have avoided costly expansions that provide excessive capacity.

Another benefit of local DG capacity is the improved utilization of existing facilities. Distribution and transmission systems alike are often sized for loads that occur only a few hours per year. Local distributed generation operating as utility peak shavers enable the wires infrastructure to be sized for base and intermediate load levels, resulting in greater efficiency and asset utilization for the system as a whole.

Contingency Capacity Support

Contingency capacity support is analogous to capacity support with the exception that the DG is sited to ensure there is enough emergency or contingency capacity in the event of a major component failure. This capacity can reduce the number of customers out of service for a particular outage, and/or reduce outage duration for particular transmission line sections.

Utilities typically design the distribution system, and to a greater extent the transmission system, so that one or more major components may fail without interrupting the power supply to customers. In a network lines from other substations taking an additional share of the load would accommodate transmission system for example, the loss of one line between two substations. Lines and other equipment have emergency ratings that are higher than their normal ratings for these events. The emergency ratings are based on thermal limitations and can only be utilized for limited periods of time.

Capacity planners perform contingency simulations to evaluate the system's ability to maintain supply given the loss of different components. In local planning projects, there are usually a handful of components – major line feeds – that presents the greatest challenge if a failure occurs. The resulting benefit from DG depends on the type of problem caused by the contingency, of which there are two fundamental classes: 1) the current-carrying capacities of lines are exceeded; 2) the voltage drops too low following the component loss. Part of the DG benefit comes from simple support of the voltage. Another part comes from the reduction of losses when the excess power imported from remote sources is displaced by the DG, or congestion is relieved through a better distribution of power among the remaining lines (the power flow balance benefit is discussed in greater detail in the next section).

If properly located, a relatively small amount of generation can make a large difference supporting transmission capacity during contingencies. If the DG is too far, electrically, from the affected area, only a fraction of the output is beneficial. However, if it is in a particularly good location (determined by power flow studies), the grid can supply more additional load than the rating of the DG. That is, the DG output is more than 100% beneficial. In one recently documented case study, a 1 MW DG interconnected on a radial distribution system permitted the serving of 1.9 MW of additional load from the transmission network.[82] Similar research related to this study uncovered situations in which the capacity benefit ratio was even greater for certain types of congestion. The key point in cases such as this is that the DG's benefit due to its impact on voltage and power flow is entirely location-specific. The same 1 MW generator located on a neighboring distribution feeder may have no beneficial impact at all on the particular contingency capacity.

The lesson from such case studies is that any benefits to the transmission system that might be derived from DG on the distribution system are location-specific and limited, possibly declining as the amount of DG increases. Widely dispersed DG can increase some of the benefits and reduce the locational dependencies.

Capacity expansions are implemented to solve contingency limitations even if the lines have significant excess capacity during normal conditions. Therefore, a DG system installed for contingency capacity could provide as much economic benefit to the utility as one installed for normal capacity, even if that emergency capacity is rarely needed.

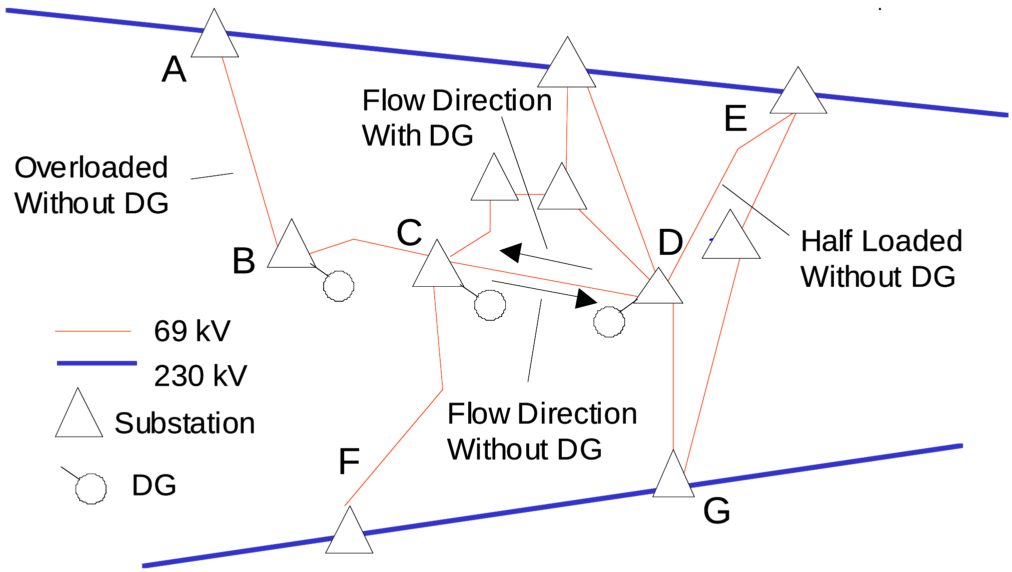
Normal and contingency capacity support applications will overlap if the overloads in both conditions occur on the same components. The economic benefit calculations are also analogous to those previously discussed for normal capacity support.

Power Flow Balance

DG operating for the benefit of transmission systems could help to improve the balance of flows among segments of a network. Figure 21 shows an example sub transmission network fed from multiple transmission sources. The thicker (blue) lines in this example are 230 kV bulk transmission lines that cross the local area. The thinner (red) lines represent a localized 69 kV sub transmission network. Power flows from the 230 kV to the 69kV lines are determined by the distribution of loads among the various substations, the location of bulk system generators (outside of this local area), and a myriad of other factors. In some cases, flows from the 230 kV to the 69kV will be unbalanced to the point that one transmission line is carrying an excessive amount while a nearby line is carrying only a small fraction of its rated capability.

In this stylized example, the net power without any DG installed is flowing from substation C to D, and the line from A to B is operating near an overload state, while the line from E to D is supplying less than half of its rated capability. Engineering studies might then show that a reasonable penetration of DG in the area of substations B, C and D would change the flow direction from D to C and counteract the imbalanced flows from the 230 kV line. To the extent an aggregate group of DG can be controlled to adjust the load allocation among a number of substations, a utility or ISO can maintain an optimal balance of flows on the network segments.[83] Generators with a wide range of reactive power control may also help to improve power flow balances by adjusting the voltage at the various substations. In many constrained networked systems even a small change in reactive power support from the DG at one bus can cause a significant shift in flows in the neighboring lines.

Figure 21. Flow Characteristics on an Example Transmission System



Losses Reduction

DG operating in the distribution system reduces the current flowing from the utility through transformers and conductors to the area served. Losses in these components are proportional to the square of the current, so offsetting load with DG reduces losses, and the effect is most dramatic during peak load periods.

DG's impact on reducing losses is generally larger on the distribution system than it is on the transmission system because of the lower incremental changes in current for a particular generator size. However, with sufficient DG penetration levels, the change in losses and their economic value are quantifiable and do have an impact on transmission capacity, congestion and voltage.

If dispatched properly during peak periods, the marginal loss reduction provided by DG will also impact the distribution substation's total installed capacity as seen by the transmission system and the ISO. This could in turn impact the allocation of capacity and ancillary service charges made by the ISO to the various utility distribution companies.[84]

DG's impact and economic value with respect to reduced losses will not always be straightforward. The behavior of the transmission system is more complex and variable than the distribution system due to the fact that network power flows are multi-directional and are derived from multiple sources. DG's impact on losses may be particularly important during contingencies that force power to be imported from remote sources. As an example, assume that the transmission network shown in Figure 21 is normally capable of serving 1000 MW while in a certain contingency condition. If a critical transmission interconnected generator in the middle of this network is inoperable during the contingency, more power drawn from units on the periphery of the network will be required. In such a case, the first added increment of well-placed DG could yield savings of 10% or more of its output in network losses alone. In other words, adding a 1 MW generator on a distribution feeder served from the area of greatest impact may free up 1.1 MW of transmission capacity due merely to reduced losses. This is in addition to any capacity that may be relieved as a result of improved voltage or power flow balance, as was discussed earlier. In such cases, the percentage savings will decline with additional DG units because the impact is less dramatic as the congestion is relieved.

In one case study performed by the authors, the incremental loss savings on a network serving approximately 2500 MW of load began at 10% (of DG capacity) and declined to an average 6% as the generation in one location was increased from 0 to 300 MW.[85] Therefore, the last increment of generation added yielded relatively little loss improvement. This nonlinear characteristic is to be expected and shows up not only in losses but also in voltage improvement and other measures of congestion relief. It reinforces the notion that there is a limit to the contingency or congestion benefit can be achieved from DG at any particular location. To further illustrate the locational nature of benefits from distribution-connected DG, this incremental loss improvement analysis was also performed for 300 MW of generation dispersed among several substations in increments of approximately 2.5MW rather than in one location. This had nearly double the impact on loss reduction. Furthermore, it enabled the system to serve the load during the most severe contingency for 2 to 3 more years than with the same amount of generation in a single location. The dispersed case was much less susceptible to the location of power delivery component failures or central station outages.

Voltage Support

Power supplied by DG in the distribution system reduces the load at the substation, and therefore reduces the voltage drop on transmission or sub transmission lines serving the substation. If the local utility in charge of the area sub transmission lines is facing voltage problems during peak loads, a sufficient amount of DG can be dispatched to support the voltages as needed. This application is distinct from the Reactive Power/Voltage ancillary service because it is applied for the local utility in effect for capacity purposes. Consequently, voltage support benefits may often overlap with those of both capacity and loss reduction.

As with the Reactive Power/ Voltage Support ancillary service, voltage support can be supplied from DG by injecting real power or reactive power. Simply operating a DG unit can provide some voltage support due to the power (MW) displaced by the DG. Reactive power has a more direct impact on voltage drop than does real power because it directly counteracts the demand created by inductive impedance in lines, transformers and certain loads that causes most of the voltage drop in the system. Hence, utilities often use capacitors – essentially reactive power sources – to offset the inductive demand and raise voltage. Many technologies employed in smaller generation devices do not produce reactive power, but those that do, such as synchronous generators and advanced power electronic converters, could use this capability to provide additional voltage support benefits. From a practical standpoint, the DG control must operate in concert with any switched capacitors located nearby on the distribution system. These capacitors switch on and off automatically given local system need, and may de-energize if DG is effectively solving the distribution problem. Therefore, if the transmission system is to see the benefit from DG's reactive power production, the capacitor controls will need adjustment so that both the capacitor and DG can produce VARs simultaneously.

Equipment Life Extension

Another benefit that has been ascribed to DG is the extension of equipment life. If applied in a way to reduce the amount of time power line components are subjected to current (thermal) overloads, DG is effectively preventing premature failure or aging of those components. Utilities use guidelines to limit the operation of these components in such a manner that the expected lifetime is preserved, but these limits can be exceeded during extreme peak load situations. The application of DG to help keep components operating within ratings certainly helps prevent premature loss of life, but it is impractical to apply economic value to the benefit defined this way. Utilities do not have access to or keep historical record of the data that would be needed to properly evaluate a DG's impact on equipment life. Moreover, the guidelines describe the loss of life calculations merely for providing operating guides, not for accurately predicting the life of the component.

The usefulness and value of DG for equipment life extension is better achieved in support of aging components (in calendar years) or facilities set in harsh environmental conditions. Projects to replace older transmission lines or substations can be deferred if the application of DG helps reduce loading to some pre-determined de-rated value based on age or ambient conditions. In such an application, the cost benefits become analogous to those associated with capacity deferral projects.

Detailed Transmission Service Definitions- Ancillary Services

Table 28 below lists each of the ISO ancillary services, along with the method of procurement.

Table 28. A/S Functions, Descriptions And Mode Of Payment

Service	Description	Payment
AGC/ Regulation	Generators regulate output and voltage (instantaneous response to ISO pulses) to improve system flow and stability.	Daily Procured Services through A/S Market
Spinning Reserve	A quantity of unloaded capacity synchronized to the grid that will ramp up within 10 minutes	Daily Procured Services through A/S Market
Non- Spinning Reserve	A quantity of capacity that is not synchronized to the grid but can ramp up within 10 minutes	Daily Procured Services through A/S Market
Replacement Reserve	A quantity of capacity that will ramp up within 60 minutes	Daily Procured Services through A/S Market
Reactive Power/ Voltage	Generators maintain voltage within ISO tariff specified power factor range. Most of the VARs required by the ISO are procured competitively, via term contracts. During periods in which the ISO needs additional VARs, it will procure them competitively in a real- time market.	Based on opportunity cost of reducing energy output to increase reactive production.
Black Start	Generators energize portions of blacked-out grid as part of orderly restoration process.	Based on contract negotiations

Regulation (A/S)
Regulation and Automatic Generation Control (AGC) refer to a generator's ability to adjust power output, voltage, and frequency in a manner that helps to stabilize the bulk system supply voltage and frequency, meet deviations between actual and scheduled load, and maintain interchange schedules. An automated governor control reacts to perceived system fluctuations by adjusting its output to oppose or dampen the fluctuation, whether it is caused by load changes or the output of other bulk system generators as they ramp up or down. It is a critical service to the stability of day-to-day grid operation.

To provide regulation service, a generator must have a strict set of capabilities and requirements. The California ISO defines regulation requirements as follows:

A Generating Unit offering Regulation must have the following operating characteristics and technical capabilities:

(a) It must be capable of being controlled and monitored by the ISO Energy Management System (EMS) by means of the installation and use of a standard ISO direct communication and direct control system, a description of which and criteria for any temporary exemption from which, the ISO shall publish on the ISO internet Home Page.

(b) It must be capable of achieving at least the ramp rates (increase and decrease in MW/minute) stated in its bid for the full amount of Regulation capacity offered.

(c) The Regulation capacity offered must not exceed the maximum ramp rate (MW/minute) of that Unit times a value within a range from a minimum of ten minutes to a maximum of thirty minutes, which value shall be specified by the ISO and published on the ISO internet Home Page.

(d) The Generating Unit to ISO Control Center telemetry must in a manner meeting ISO standards include indications of whether the Generating Unit is on or off AGC at the Generating Unit terminal equipment.

(e) The Generating Unit must be capable of the full range of movement within the amount of Regulation capability offered without manual Generating Unit operator intervention of any kind.

Distribution-level DG needs to be large and highly coordinated to be utilized by an ISO for regulation services. With low penetrations, there will be little use for DG in regulation. This is discussed in greater detail later in the penetration guideline section of this report

Spinning Reserve (A/S)

Spinning reserve is supplemental generation capacity that is ready to quickly ramp up at the request of the ISO. The term spinning refers to the fact that the generator is on, spinning at rated speed (in the case of turbine generators), and synchronized to the grid. It only needs to adjust its power output to the prescribed level.

The California ISO defines spinning reserve service requirements as follows:

Each Generating Unit or external import of a System Resource scheduled to provide Spinning Reserve must be capable of converting the full capacity reserved to Energy production within ten minutes after the issue of the Dispatch instruction by the ISO, and of maintaining that output or scheduled interchange for at least two hours.

Each Participating Generator shall ensure:

(a) That it's Generating Units scheduled to provide Spinning Reserve are available for Dispatch throughout the Settlement Period for which it has been scheduled; and

(b) That it's Generating Units scheduled to provide Spinning Reserve are responsive to frequency deviations throughout the Settlement Period for which they have been scheduled.

Large DG and aggregated small DG alike can provide spinning reserve service. Implicit in the definition however, is the availability of the capacity to be called upon at any time. Therefore, a DG unit cannot use capacity for peak shaving a local load, for example, and at the same time qualify that capacity for spinning reserve. This limitation is true for non-spinning and replacement reserve services as well. A generator designed to run at 80% of its normal capacity for local purposes can qualify the remaining 20% capacity for spinning reserve, as long as it is synchronized to the grid for the defined reserve period.

Non-Spinning Reserve (A/S)

Non-spinning reserve is similar to spinning reserve in the sense that it is counted on to ramp up to a prescribed output level within a prescribed timeframe. The difference is that the generator does not need to be on and synchronized to the grid. Generators that can start, synchronize and ramp to full power in short time periods can therefore participate in the fast-response reserve market without running at all times. In addition, customers in the form of curtailable load may provide non-spinning reserve services.

The California ISO defines non-spinning reserve service as follows:

Non-Spinning Reserve may be provided by, among others, the following resources:

(a) Demand that can be reduced by Dispatch
(b) Interruptible exports;
(c) On-demand rights from other entities or Control Areas;
(d) Off line Generating Units qualified to provide Non-Spinning Reserve;
(e) External imports of System Resources.

Each resource providing Non-Spinning Reserve must be capable of converting the full capacity reserved to Energy production within ten minutes after the issue of the Dispatch instruction by the ISO, and of maintaining that output for at least two hours.

Each provider of Non-Spinning Reserve must ensure that its resources scheduled to provide Non-Spinning Reserve are available for Dispatch throughout the Settlement Period for which they have been scheduled.

Non-spinning reserve in most cases will be a more appropriate choice over spinning reserve for unused DG capacity. Most distribution level DG technologies do not require ten minutes to start up, and therefore would not gain from remaining synchronized to the grid when not needed. Non-spinning reserve further provides ample opportunity for generators installed as emergency back-up systems to participate in the reserve market, where they would not under spinning reserve. These generators are designed to remain off under normal circumstances and serve the customer's load only if the utility experiences an outage, so their capacity during normal utility operation is always available.[86]

Replacement Reserve (A/S)

Replacement reserve is very similar to non-spinning reserve with the exception that the generator has 60 minutes to start and ramp up instead of only ten. As is the case with non-spinning reserve, curtailable load qualifies for providing the service.

The California ISO uses replacement reserve to allow restoration of dispatched operating reserve, and defines the requirements as follows:

Each resource providing Replacement Reserve must be capable of supplying any level of output up to and including its full reserved capacity within sixty minutes after issue of Dispatch instructions by the ISO.

Each resource providing Replacement Reserve must be capable of sustaining the instructed output for at least two hours.

Replacement Reserve may be supplied from resources already providing another Ancillary Service, such as Spinning Reserve, but only to the extent that the ability to provide the other Ancillary

Service is not restricted in any way by the provision of Replacement Reserve. The sum of Ancillary Service capacity supplied by the same resource cannot exceed the capacity of said resource.

Replacement reserve can be provided by large and aggregated small DG that requires more than ten minutes to start and ramp to full power. This would be appropriate in cases where the generator technology itself has ramping limitations, or where the generator starting functions are not automated in response to a signal from the ISO, and therefore require delayed manual intervention.

Voltage Support (A/S)

Voltage support services are required to maintain transmission voltage levels and reactive power margins within area coordinating council and NERC criteria. Generators and loads may be dispatched and operated within a prescribed power factor range to boost the voltage during heavy load periods, or reduce the voltage during light load periods. The service can be provided by generators, loads, and utility distribution companies (UDCs) alike, as long as they have the proper power factor adjustment capabilities.

The California ISO defines voltage support service requirements as follows:

A Generating Unit providing Voltage Support must be under the control of generator automatic voltage regulators throughout the time period during which Voltage Support is required to be provided. A Generating Unit may be required to operate under excited (absorb reactive power) at periods of light system demand to avoid potential high voltage conditions, or overexcited (produce reactive power) at periods of heavy system demand to avoid potential low voltage conditions.

The Generating Unit must be able to produce or absorb VARs outside the 0.90 lag to 0.95 lead bandwidth over a range of real power outputs which the Generator expects to produce when offering Voltage Support;

Generating Units providing Voltage Support must have automatic voltage regulators, which can correct the bus voltages to be within the prescribed voltage limits and within the machine capability in less than one minute.

Because generators and loads alike can provide voltage support services, distribution level DG can contribute to the service on behalf of the UDC. In this case, the UDC would use the DG systems to adjust the voltage and power factor of the substation from the perspective of the transmission system.

Black Start (A/S)

Black start services refer to the ability of a generator to start-up and energize a dead bus following an outage. Generators are started in a sequence so that each subsequent generator has an energized bus with which to synchronize. Strategically located black start generators are a key factor for ensuring timely restoration after a major outage.

The California ISO identifies Black Start service performance characteristics as follows:

Each Black Start Generating Unit must be able to start up with a dead primary and station service bus within ten minutes of issue of a dispatch instruction by the ISO requiring a Black Start.

Each Black Start Generating Unit must provide sufficient reactive capability to keep the energized transmission bus voltages within emergency voltage limits over the range of no-load to full load.

Each Black Start Generating Unit must be capable of sustaining its output for a minimum period of 12 hours from the time when it first starts delivering Energy.

The ISO will select Black Start capacity in locations where adequate transmission capacity can be made readily available (assuming no transmission damage) to connect the Black Start Generating Unit to the station service bus of a Generating Unit designated by the ISO.

As in the case of regulation, the opportunities of distribution level DG in the black start market are slim. DG at this level is realistically incapable of energizing a significant portion of the local transmission area. It’s potential benefit lies in creating small islands in the distribution systems that minimize the loading requirements on bulk system generators.

Guidelines for DG Transmission Services

Participation

The role of DG in providing ancillary services (A/S) – and receiving appropriate compensation – is currently under debate in California. Issues related to DG have been raised in a variety of proceedings, including the California Public Utilities Commission (CALIFORNIA PUBLIC UTILITIES COMMISSION) proceeding on DG (R.99-10-025) and several cases pending before FERC. The ISO held two public forums on the subject during August 2000. While the issues are still unsettled, the ISO is moving to improve the prospects for distribution level DG participation in the A/S markets.

Proponents of DG contend that ISO requirements generally favor larger generating units in market access and technical requirements. In particular, DG proponents have expressed concerns about:

- The ISO interpretation of the term "Participating Generators" in the Tariff to mean any Generating Unit. This interpretation places the burden of ISO requirements (and high costs) on small DG units. The ISO could require all DG, regardless of size, to be ISO Metered Entities and could require EMS telemetry.
- Until recently, the inability of small DG, under 10MW, to participate in ISO-administered markets (such as the A/S market).
- The prohibition in the ISO Tariff against net metering of on-site or "over-the-fence" load against the output of DG, and the attendant requirement to schedule (and have ISO charges assessed on) "behind-the-meter" customer load that is served by DG above specified sizes.

In consideration of these issues, the ISO recently applied to FERC for several changes to the ISO tariff that will improve DG access to ISO controlled markets.[87]

The amendments are intended to reduce barriers to the implementation of small DG, without unduly impacting the ISO's ability to maintain system reliability, and without establishing the basis for significant cost shifting. Specifically, the Tariff amendments would provide the following:

- A/S Market Participation. The amendment reduces the threshold for A/S participation (and SE participation) by Generating Units from the current 10 MW minimum to a 1 MW minimum.

- Net Metering. The amendment will allow net metering (metering for onsite generation that nets generation and load) for DG less than 1 MW. A number of customers and DG proponents note that the ISO's prohibition ignores the fact that for purposes of CA ISO operations, DG acts like a reduction in load and the fact that it has been California practice to meter at the point of common coupling rather than to separately meter generation and load.

The ISO estimates about 50-75 MW of DG will fall under this provision. These DG units will therefore reduce the cost to the UDCs to the extent that their metered loads will be reduced and the ISO charges will decline. Likewise, the overall demand for A/S by the ISO will be relieved.

- Non-Market Participants. The amendment will establish that DG units under 1 MW that do not participate in the ISO A/S or SE markets are not "Participating Generators". This relieves them of the requirements of ISO Metered Entities and would provide significant cost savings to the DG owner.

  The amendment will also provide that DG units under 10 MW that do not participate in A/S-SE markets will not be required to have EMS telemetry. Most DG proponents object to any ISO requirements that are applied to DG units that do not actively participate in these markets, and therefore welcome creation of a category of DG that would be exempt from ISO requirements.

In addition to competing directly in the A/S market, the "redesign" of the A/S market provides the opportunity for these services to be traded between Scheduling Coordinators (SCs). The DG owner could contract to provide ancillary services directly. In turn, SCs could trade these services with other SCs or could receive "self provision credits" from the ISO, reducing their overall obligation to purchase services from the ISO.

While these developments open up the A/S market to DG, the owner/developer of DG must understand that participation imposes other obligations. As alluded to earlier, certain modes of operation are incompatible with participation in other markets. For example, an on-site DG generator that is controlled to reduce demand on a customer meter cannot simultaneously be used for spinning reserve, except to the extent that a portion of the generator capability is set aside, unused, for this purpose.

The optimal economic use of the DG unit may therefore be a trade-off between the cost savings of peak reduction and the revenues associated with A/S. A similar trade-off exists for combined heat and power applications that impose power operating conditions upon generators in order to meet heating loads.

Penetration

Issues surrounding DG penetration on the T&D system have been the subjects of much attention in the past several years. One of the most visible of current activities is that of the IEEE P1547 committee, a large group of experts from utilities, DG technology companies, the National Renewable Energy Laboratory (NREL) and various other third parties. The group is focusing on the development of a standardized set of interconnection recommendations for DG on the distribution system.[88] Early drafts of this standard categorically defined penetration to be low if total DG capacity is less than 30% of a feeder's peak load, or high if the capacity to feeder peak ratio is higher than 30%. The drafts also defined generalized maximum ratings for DG systems as a function of the interconnecting voltage. For example, the recommended maximum generator penetration on a 12.5 kV system was 3 MVA, whereas a 34.5 kV feeder could have up to

10 MVA of generation. These maximum values were derived from generalizations of the strength or stiffness ratio of a feeder, which is the ratio of a generator's short-circuit contribution at the point of common coupling (PCC) to the combined generator and utility short-circuit contribution. However, these types of generalizations are contentious for both sides, and were removed from later drafts of the standard because they do not adequately reflect the site-specificity of DG installations.

The more important objective recognized in defining distribution penetration is not determining an absolute threshold, but determining guidelines for the degree of analysis required by planners responding to DG installation applications. The California Energy Commission's development of interconnection requirements is a case in point.[89] It has established a screening process for utilities that triggers further evaluation if the aggregate generator capacity on any line segment is equal to or greater than 15% of that line section's peak load. The line section approach helps to properly treat penetration level not as a fixed number but as a curve that varies according to feeder size and the DG's specific location. For example, 15% of the line section peak load close to the substation may be far greater than that of a line section several miles downstream on the same circuit.

Generalizing penetration requirements on the transmission system can be equally difficult, although the concern from the utility perspective is reversed: conservative limits placed on DG size to minimize disruption of distribution system operations would result in mostly imperceptible penetration levels from the transmission perspective.

The level of load reduced at the substation will almost exclusively define transmission's perspective of distribution level DG penetration. It is doubtful there would be any advantage to siting enough DG in the distribution system to serve as an actual power source to the transmission system (back feed). In most cases, local area loads peak concurrently with the system peak, so to back feed for transmission benefits, the DG would have to be sized greater than the peak load of the circuit it is supporting, and would have to be sited at the substation. The case of an area that historically is lightly loaded during system peak is the exception, not the rule. Even in such cases, there would be significant resistance on the part of UDC operators to intentionally back feed the transmission system. Therefore, discussions of DG penetration on the distribution system are normally confined to fractions of the distribution load.

In that context, effective penetration from the transmission perspective becomes that of sufficient load reduction or modification to impact operation. As in distribution, this is site specific, but some generalizations can be made. DG will have more impact on capacity given lower transmission connecting voltages, due to the fact that the same DG power output creates lower currents on higher voltage systems.

Table 29 illustrates this relationship using an example 5 MW plant connected to a 600 Amp line segment. At the lower (distribution) voltages, the contribution of the plant ranges from 14% to 40% of the 600 Amp line capacity. The maximum impact at sub transmission voltage levels is 8%, and lowers still at the higher transmission voltages.

More units and strategic siting can quickly increase the impact to the transmission system. If there are ten 5 MW plants located at substations along the same transmission line, the impact for example on a 161 kV line would be 30%. This is far more than would be necessary to substantially defer an upgrade project.

Table 29. Amperage And Capacity Of A 5 Mw Dg System On A 600a Line

Voltage (kV)	Current (A)	% of Line Capacity
12	241	40%
21	137	23%
34	85	14%
60	48	8%
121	24	4%
161	18	3%
230	13	2%
500	6	1%

The same logic and analysis methods apply to contingency capacity, reserve and life extension applications. For power balancing applications, power flow models currently used today will determine the amount of load reduction necessary from DG to sufficiently alter the flow patterns.

The impact of uniform penetration levels on reduced losses, and their associated savings, in most cases can be treated with a more straightforward analysis. Reduced loading at substations due to the presence of DG reduces losses on the transmission system proportional to the square of the current. The value is greater with higher penetrations of DG, just as it would be with actual demand reduction during peak loading periods. The major exception to this generalization, as described earlier, is in cases where contingency or congestion-related losses are significantly impacted by site-specific DG.

For voltage and reactive power support applications, transmission voltage levels are again a critical factor, as is the ability of the DG system to alter its power factor. Using the same example as before, Table 30 shows the impact of a 5 MVA DG system producing purely reactive power (from a DC-AC inverter, e.g.) on the power factor of a 600 Amp circuit at different voltage levels. In each case, the load is 90% of rated capacity, or 540 Amps. The power factor is improved in each case because the DG reduces the reactive power demand from the utility supply. With the lower distribution voltages, the power factor improves from 0.85 to over 0.9, and therefore has a much greater impact on reducing the current transmitted on the lines. At the higher transmission voltages, the impact becomes insignificant.

Table 30. Impact Of 5 Mva Dg In Reactive Power Mode On Example Circuit Power Factor

Voltage (kV)	MVA @ .85 PF	MW	Power Factor with DG (Reactive Power Mode)
12	11	10	1.00
21	20	17	0.95
34	32	27	0.92
60	56	48	0.89
121	113	96	0.87
161	151	128	0.86
230	215	183	0.86
500	468	398	0.85

Penetration levels sufficient for regulation/AGC applications in any given case are both greater and more complex. To play a useful role in regulation, the ISO will need to determine how controlled load reduction can or would be applied in different operating scenarios. System stability simulations at the bulk level can be used to identify impacts and opportunities. Penetration studies dating from the 1970s have described the potential challenge DG might cause for existing generation AGC control functions. A scenario often portrayed was the control and stability problems resulting from a large penetration of renewable power sources, whose outputs are intermittent and relatively unpredictable. Less attention was paid to using the DG proactively for regulation. In the current utility environment, AGC regulation functions may therefore be focused on limiting the impact or disruption to existing area control, by limiting large step changes in the output of large aggregated DG supplies.

The principle of limiting disruption caused by DG has an analogy in distribution functions as well. Penetration may be too high on the distribution system if the feeder voltage drops too low as a result of DG capacity suddenly dropping from the system. If large enough, this voltage drop could cause problems to nearby customers. It may even cause inadvertent operation of current protection devices at the substation if the inrush current from the transmission system is too high.

In light of this, the near term role of DG in regulation may be to limit disruption. In a fully evolved electric power system where DG routinely serves over 30% of customer loads, regulation will make more sense as a proactive service.

Finally, any support that DG is able to provide for black start operations is highly dependent on penetration. As described earlier, DG's role in an evolved infrastructure is less likely to be in creating a supply to synchronize to as it is to reduce the loads that other larger generators must pick up. System level models to determine their usefulness can analyze a large or aggregated group of DG.

Communication Issues

A transmission system reliant on large numbers of dispersed generators will require a communications infrastructure that is far more extensive than that which exists today. Distributed automation (DA) technologies today are used in a relatively small number of UDCs. These technologies form a backbone for monitoring the status of local system operation and for controlling devices such as capacitors and sectionalizing equipment. DA is still considered more of a luxury than a necessity by most utilities, but a similar backbone of control and monitoring functionality will be necessary if DG participates in various transmission services.

The ISO already has specifications for generator communication systems. For example the California ISO specifies:

For Regulation:
A direct, digital, unfiltered control signal generated from the ISO EMS through a standard ISO direct communication and direct control system, must meet the minimum performance standards for communications and control which will be developed and posted by the ISO.

For Spinning Reserve:
ISO approved voice communications services must be in place to provide both primary and alternate voice communication between the ISO Control Center and the operator controlling the Generating Unit or System Resource; and the operator of the Generating Unit or System Resource must have a means of receiving Dispatch instructions to initiate an increase in real power output (MW) within one minute of the ISO Control Center determination that Energy from Spinning Reserve capacity must be dispatched.

For Non-Spinning Reserve:
The communication system and the Generating Unit, System Resource or Load must pass a qualification test to demonstrate the overall ability to meet the performance requirements of the ASRP for Non-Spinning Reserve.

For Voltage Support:
Metering and SCADA equipment must be in place to provide both real and reactive power data from the Generating Unit providing Voltage Support to the ISO Control Center.

Ten megawatt-sized installations may be controlled separately or in groups by the ISO for agreed upon A/S functions. A third party may be involved to represent a specific group of generators for communications, particularly in cases where alternate voice contacts are required. For example, an energy service company (ESCO) may lease a large number of similar generating units to interested customers. The lease price is reduced if the ESCO is able to operate the generators in part on behalf of the ISO. In that case, the ISO may use the ESCO as a single point of contact to control the multitude of leased generators. This simplifies the tasks of the ISO while allowing the ESCO to achieve greater value with their systems. The incremental or marginal value to a single customer may also be too small to forfeit some amount of control. A particularly powerful example of this problem would be a case in which the generator was prohibited from operating at a time when a customer's demand was likely to exceed a previous ratcheted demand.

Summary and Conclusions

This report has discussed how DG, under current market conditions and penetration levels, can provide benefits to the transmission system. The benefits that DG can provide to the transmission system are categorized as localized, in which site-specific generators help support local capacity or voltage constraints, and bulk level benefits defined by the Ancillary Services market.

The amount of installed DG relative to the system total load, or penetration, is the most important factor for the influence of DG on transmission operation. A single 2 MW generator may have considerable impact on the operation of a distribution system, while going wholly unnoticed on the transmission system.

In today's environment, distribution interconnected DG is technically capable of providing a number of specific transmission level services.

The localized benefits of DG have the most potential to provide significant value. DG's ability to provide the localized benefits (normal capacity, contingency capacity, and life extension) is highly dependent upon:

- Siting location,
- The aggregated size and control of the DG, and
- DG capabilities for on-peak dispatch.

DG can also provide benefits through the reduction of losses on the transmission system. To some extent, this benefit can be independent of where the DG is sited. The benefits of loss reduction from DG can be quite high during contingencies, but in such cases appropriate siting is also critical. The losses benefits attributable to DG decrease with higher DG penetrations and off-peak operation.

For power flow balancing and voltage/VAR support, siting of DG is also very important. DG technologies, which can produce reactive power, have greater capabilities to provide these services. In providing these services, DG operating control must be coordinated with local distribution voltage measures.

DG is also capable of providing some ISO ancillary services. The reserve services (Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve) can all be supplied by DG. Non-spinning Reserve may be the most appropriate application given the short start-up times and operating efficiencies of most DG currently in the field.

DG is also capable of providing voltage support services on behalf of the local UDC. UDCs can use DG to adjust the voltage and power factor of substations as seen by the transmission system.

There are two ancillary services in which DG is less likely to be able to play a role. AGC would require large aggregations of capacity and control. Given DG's small size relative to local transmission loads, it is also unlikely that DG could provide significant Black Start benefits.

ISO rules and tariff terms and conditions for ancillary services define the degree to which DG can participate in markets for which it is technically capable. As DG markets evolve, the role DG can play in transmission services will increase. In addition, there are localized capacity related benefits from DG for which there are no currently institutionalized methods to capture their values. This is in part due to the fact that many of the benefits are very location specific. As markets for DG mature, cost effective management of the bulk transmission system will require the consideration of DG benefits in evaluation of alternatives to new capacity and traditional methods of providing these services.

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Appendix A: California ISO Tariff Amendment 35

The following section is reproduced from the ISO's filing to FERC on December 29, 2000.

PROPOSED ISO TARIFF REVISIONS

Distributed Generation

In the course of discussions with stakeholders and in the context of a proceeding before the California Public Utilities Commission ("CALIFORNIA PUBLIC UTILITIES COMMISSION") regarding distributed Generation, concern has been expressed about the impact of ISO requirements on small-distributed Generators.

Accordingly, the ISO has undertaken a review of its requirements to determine whether these could be in some instances clarified and in other instances modified to reduce barriers related to ISO requirements on small-distributed Generators while maintaining system reliability and minimizing cost shifting.

The ISO has identified a number of modifications to its requirements for small distributed Generators, and proposes the modifications to its Tariff shown in Attachment B to this filing, that will accomplish the following:

- Clarification that a distribution-level Generating Unit under 1 MW that does not participate in the ISO's Ancillary Services and/or Imbalance Energy markets is not a "Participating Generator" and is not required to be an ISO Metered Entity;
- Reduction of the minimum rated capacity threshold for Generating Units to participate in the ISO's Ancillary Services markets from 10 MW to 1 MW, and provision of flexibility to undertake programs for aggregation of Generating Units under 1 MW to participate in such markets;
- Clarification that a distribution-level Generating Unit of under 10 MW that does not participate in the ISO's Ancillary Services and/or Imbalance Energy markets is not required to install ISO telemetry; and
- Addition of provisions that will allow net metering arrangements for distribution-level Generating Units under 1 MW.

These changes were developed with substantial stakeholder input, including many discussions in the context of the CALIFORNIA PUBLIC UTILITIES COMMISSION's proceeding, an introduction to the changes at the ISO's August 9, 2000 Market Issues Forum, and an all-day discussion meeting with numerous Market Participants on August 31, 2000. Several drafts of the Tariff revisions have also been circulated for stakeholder comment.

Most stakeholders support the revisions, although many argue that the changes do not go far enough, particularly in addressing requirements for all on-site loads, irrespective of the size of the Generator. During the November 29, 2000 ISO Governing Board meeting, the Board approved the attached Tariff revisions, but directed the ISO to further discuss issues related to on-site load with stakeholders and the CALIFORNIA PUBLIC UTILITIES COMMISSION. To the extent that any further revisions to the ISO Tariff may be appropriate to accommodate distributed Generation, those revisions will be developed after these discussions and will be the subject of a future filing.

The ISO believes that the Tariff revisions shown in Attachment B will reduce barriers to small-distributed Generators and will accommodate the participation of additional resources in the ISO's markets. Accordingly, the ISO requests waiver of the 60-day prior notice requirement so that these revisions may be permitted to go into effect on January 1, 2001.

Benefits and Pricing Strategies for Services Provided by DG and DSM to the Distribution System

Summary

There is increasing recognition among distributed resource technology manufacturers and owners as well as in the electric utility industry that distributed resources (DR) are technically capable of reducing costs and improving performance of electric distribution systems. The provision of electricity distribution services consists of many "bundled" services, which under today's utility market and regulatory environment are provided to customers under a single service definition and price. This report identifies the components distribution service that DR are technically capable of providing, and develops pricing strategies to compensate DR technologies for the economic benefit that they can offer to utility distribution companies.

This report identifies eight services that distributed generation can provide to the distribution system. These services are:

9) Capacity support;
10) Contingency capacity support;
11) Reduction of losses;
12) Voltage support;
13) Voltage regulation;
14) Power factor control;
15) Phase balancing; and
16) Equipment life extension.

The ability of DG to provide these services is dependent on the type of DG installation. So called "behind the meter DG" that reduces customer loads at the meter, DG generators not connected to customer loads (DG connected directly to the distribution system), and customer-side demand management measures (DSM) have differing technical capabilities to provide these services.

These distribution services can be divided in three types (Table 31): those that substitute or defer investment in major capital assets; those that provide power quality control functions; and those that substitute for energy purchases. The choice of pricing strategy for each of these services is largely driven by the type of service.

Table 31. Summary Of Distribution Services

Asset Substitute	Power Quality	Energy
Capacity support	Voltage support	Losses
Contingency capacity support	Voltage regulation	
Equipment life extension	Power factor control	
	Phase balancing	

This report evaluated three pricing mechanisms for distribution services: 1) bilateral agreements, 2) RFP/auction competitive procurements, and 3) posted tariffs. The recommended pricing approaches are derived by matching the attributes of the service categories to the features of the different pricing mechanisms. The major conclusions of the assessment of pricing mechanisms are listed below.

4) Bilateral agreements should rarely be used because they are likely to result in inefficient prices and can limit innovation and potential cost savings. Bilateral agreements may be appropriate for some DSM applications to overcome saturation and persistence issues with energy efficiency measures.
5) The scale of most large asset-based distribution requirements favors the RFP/auction approach where there is sufficient lead time and DR benefit to accommodate the timing and administrative costs of a competitive pricing mechanism. For routine procurements, steps can be taken to reduce the administrative burden and to encourage DR participation.
6) Services that provide power quality control functions and energy-based services are most effectively priced using a posted tariff. This recommendation is driven primarily by the relatively small and dispersed nature of expenditures (both capital and expense) for quality control, short response time, relatively minor impact of partial participation by DR owners, and the existence of tariffs for some components.

Procuring distribution services requires clear definition of the contract structure, the contract terms, and the mechanism by which the price and quantity levels are determined. Poorly designed pricing mechanisms and contracting forms can eliminate otherwise cost effective opportunities for DR to participate in providing distribution services. Adopting appropriate pricing approaches for distribution services has the potential to lower UDC costs of service and provide DR owners/operators the opportunity to share in the benefits they can provide to the distribution system.

Introduction

Electricity price unbundling typically refers to the separation of generation, transmission, distribution, and other utility costs into distinct cost accounting and ratemaking categories. The increasing recognition that generation or load reducing technologies can substitute for or delay investment in transmission and distribution assets has led to interest in distribution and transmission unbundling. In most of the United States, transmission markets have been unbundled into several services, including capacity services and ancillary services. Unbundling of distribution services has not been developed to the same degree as transmission level services. Typically, the Utility Distribution Company (UDC) provides many types of services (for example, normal and contingency capacity and power quality related services) to customers for a single bundled distribution service charge.[90] There is increasing recognition that distributed resources (DR) are technically capable of providing many of these services to distribution systems.[91] However, there are currently no clear definitions of these services, no market or regulatory mechanism to price these services, or a mechanism to arrange appropriate payment to DR owners/operators who provide them. The overall objectives of this report are to identify those distribution services that DG and DSM technologies are technically capable of providing, and to develop pricing strategies to compensate DG and DSM technologies for the economic benefit that they can offer to UDCs.

The remainder of this report is divided into four major sections. These sections address:

1. Definition of services that DG can provide to the distribution system;
2. Discussion of pricing strategies for these services;
3. Discussion of the applicability of these service definitions and pricing strategies to DSM; and
4. Conclusions.

Definition of DG Services

Electric distribution systems are planned and built to delivery energy to end-use customers. Provision of distribution service consists of many "bundled" services, and even in restructured regulatory environments such as California, these services are provided to customers under a single service definition and price. This section identifies and defines the components of distribution service, and discusses the degree to which DG technologies are technically capable of providing them.

Distribution Services

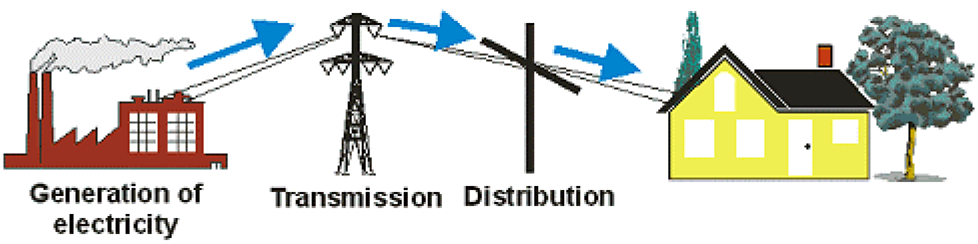
Distribution System Functionality

Role of the Distribution System

Electric distribution systems serve as the final link between the large central station electric generators that supply the nation's bulk transmission system, or grid, and the end-use customers (Figure 22). Power from central generators is converted to transmission voltages, typically over 50 kV and up to 750 kV, for delivery over long distances to local area load centers. Distribution substations located within these load centers convert the high voltage power to lower voltages, generally 35 kV or less. Power lines emanating from distribution substations deliver electricity to residential, commercial and industrial customers.

Figure 22. Fundamental Elements of the Electric Power System

Courtesy DOE



High voltages are preferred for long distance transmission because they allow the power to be delivered without excessive line losses and reductions in voltage levels. Lower voltage lines are preferred for distributing power within load centers due to a myriad of cost, feasibility and safety reasons, such as line clearance, insulation, and equipment expense.

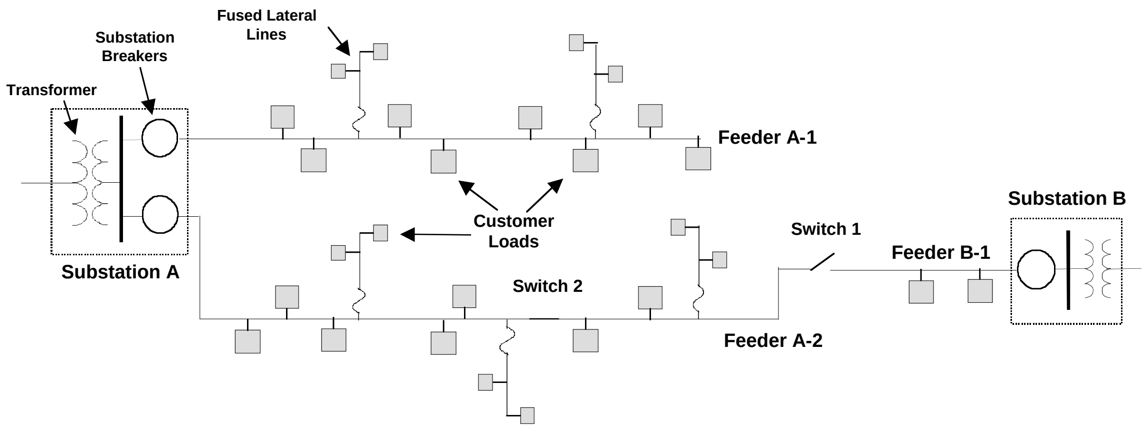
Distribution System Design Configurations

The configuration and design of a distribution system have important implications on the application and expected benefits of distributed generators. A few of the more important design considerations include configuration (radial or network), whether or not the system is underground, the interconnecting voltage, and substation design. Analysis issues and procedures will differ for the various configurations, and it is therefore important that any development of DG pricing mechanisms work within the context of distribution system design.

Utility distribution systems in the U.S. are broadly categorized as radial or network systems. In a radial system, primary distribution lines (or feeders) and their connected loads are supplied by only one substation source at a given time. A network distribution system is more similar to the transmission system, where lines and loads are interconnected as grids with more than one primary supply.

The distribution lines in a radial system are analogous to the spokes of a wheel; they emanate from a single hub without interconnection with one another. Most distribution systems are radial because of the lower cost of protection, operation and maintenance. Radial systems are prominent especially in rural areas, where geography makes the cost of providing redundant supply sources prohibitively high. Figure 23 illustrates an area served by a radial distribution system. The transformer, bus and two breakers in Substation A supply power to Feeders A-1 and A-2. Customer loads are represented by the gray boxes, and are distributed along both the primary feeder lines and the laterals that branch off. For illustrative purposes, a small section of the nearby Substation B is shown with Feeder B-1 extending out towards Feeder A-2.

Figure 23. Radial Distribution System

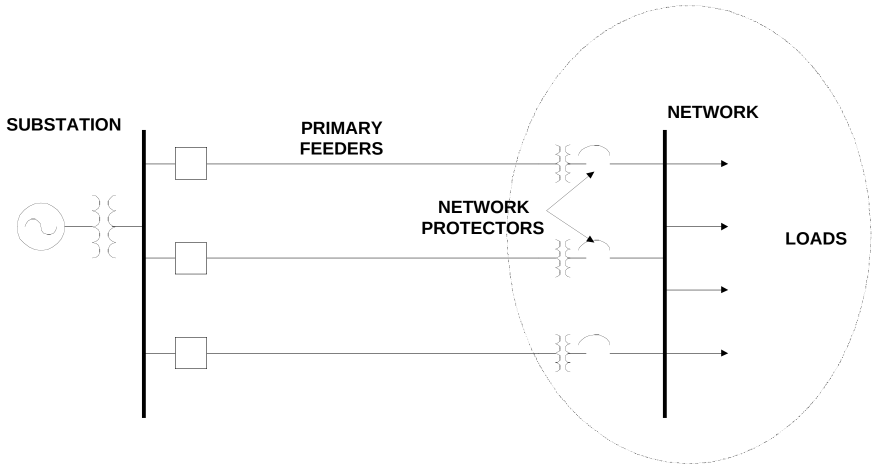


There is no direct connection between any of the three feeders shown in the figure. However, switches along feeders can be opened and closed to shift line segments to a different source. For example, the system is shown with two switches. Switch 1 is normally open and Switch 2 is normally closed, therefore the loads between the switches are normally served by Substation A. If Substation A is overloaded, system operators have the ability to shift the intermediate customers to Substation B, by closing Switch 1 and opening Switch 2. System protection practices prohibit the operation of the system with both switches closed.

From this perspective, one can see how a generator's ability to help operators distribute load among circuits and transformers is highly dependent on its location, not only with respect to the substations, but also with respect to important feeder switches.

In many urban areas and city centers, networks are used to provide greater service reliability. There are numerous types of network systems, distinguished by their connection either at the primary or secondary distribution voltage level. A secondary network is a grid operating at a reduced voltage, typically 480V, but also 120V, supplied by transformers from two or more primary distribution feeders. A highly localized secondary network system is referred to as a "spot" network. Figure 24 shows a distribution system with a secondary network. Primary feeders emanate from the substation and supply a network bus system via transformers and network protectors, which among other factors prevent power from feeding back into the primary system.

Figure 24. Secondary Network Distribution System



If large enough, a distributed generator can have significant impacts on the proper operation of network protectors. For that reason, interconnection guidelines may differ substantially for network applications, and in some cases, distributed generators may be prohibited altogether.

Benefits will also differ with network and radial systems. As an example, a distributed generator sited within a network system may provide some measure of capacity benefit for the entire (localized) network, whereas the capacity benefits on a radial system is highly dependent on the precise location of the generator. On the other hand, a generator that improves voltage or losses on a radial system may have the opposite impact on a particular network system.

Primary distribution voltages in radial and networked systems throughout the U.S. cover a fairly broad range, generally from 4kV to 35kV. Individual utilities tend to use a select few voltage levels for different radial and network applications, but the differences from one utility to the next have less to do with optimum design than with equipment and vendor selections made by early utility managers. However, efficiency considerations favor higher voltages for distribution systems with larger loads and a high number of circuit miles.

A distributed generator's impact on the distribution system is greatly affected by the interconnecting voltage. For example, the load on a 12 kV, 600 Amp feeders operating at 75% capacity is 12,000 x 600 x $\sqrt{3}$ x 75%, or 9.4 MVA. Therefore a 5-megawatt (MW) generator operating on this feeder supports over half of the peak load. The load on a similar 600 Amp feeder operating at 75% capacity but at 34 kV is 26.5 MVA. In this case the same 5 MW generators contributes less than 20% of the total feeder load.

Distribution circuits may be installed overhead or underground. Overhead systems are more commonly selected because they are far less expensive, but underground systems are common in downtown areas, commercial and industrial parks, and select residential areas. Reliability factors and statistics vary significantly between overhead and underground systems, and therefore a generator's ability to improve conditions is similarly affected.

There are also a number of different distribution substation designs. The simplest substation consists of a single transformer and one or two radial feeders. A more typical substation contains 2 to 3 transformers, 6-10 feeders and a bus system with multiple switches allowing a variety of transformer-feeder connections. The third transformer is likely to provide redundant capacity in the event that one of the two primary transformers should fail. As such, the distributed generator's importance with respect to substation capacity in both normal and emergency situations is highly dependent on the substation design.

Reliability and Quality of Service

Utility distribution companies (UDCs) plan and operate their distribution systems to meet a set of defined service standards and reliability targets. The most basic of service standards involve maintaining voltages within a prescribed tolerance to protect customer loads and utility equipment. There are a wide range of measures and indices used for reliability targets. These include localized counts of outages as well as various system wide averages of outage frequency and duration. The UDC makes few spending decisions that do not relate to the reliability of the system. However, many if not most reliability issues are not capacity related. Therefore, a distributed generator's impact on improving system reliability and solving reliability related problems is limited to a subset of utility issues.

Outages on the distribution system cause well over half of total customer interruptions, for several reasons.[92] Since there is normally only one path from the distribution substation to a given load, the loss of a link in that path means losing the capability to serve the load. Furthermore, distribution circuits cover broader geographical areas and are more exposed than transmission systems to the public, structures, trees, and animals, and are therefore more susceptible to accident related failures.

System faults may cause no interruption, a momentary interruption (five minutes or less), or a sustained interruption (more than 5 minutes), depending on the severity of the fault and the importance of the failed device. Sustained interruptions are often prevented by the operation of fault clearing devices such as fuses and re-closing circuit breakers. In such cases, most customers will only experience a momentary interruption. The annual fault rate on a typical utility overhead distribution feeder ranges from 0.1 and 0.3 faults per mile, of which about 20% develop into sustained interruptions. This rate varies regionally depending on the number and severity of storms, tree growth, and insulator contamination. On underground cables, the fault rate is typically about 0.03 per mile per year, most all of which cause sustained interruptions. Approximately two-thirds of underground faults are caused by construction dig-ins. These fault statistics usually dominate the measures of reliability on a distribution feeder.[93]

A generator installation will not prevent tree faults or pole-related automobile accidents, and therefore cannot directly reduce the related reliability statistics. Under the right conditions however, it can impact the number of customers affected by those incidences, or the duration of related outages. Little value is attributed to generators for improving reliability statistics at present because of the limitations placed on them for operating during utility outages. In time, as technology improvements are made and distribution systems are designed more with DG in mind, controlled DG "islands" will be permitted, thereby significantly increasing their value to both customers and grid operators.

A controlled DG island is analogous to a customer facility with back-up generation, but on a scale in which whole sections of a feeder are served by the back-up supply during a utility outage, rather than just the single customer. Distribution systems currently lack the switching, synchronizing, and protection equipment necessary for smooth transfers between normal and island modes of operation. Adding this capability to conventionally planned distribution systems would not likely provide sufficient value for the cost, but future systems designed for more dynamic power flow operation would benefit from the capability.

Major Distribution System Components

Distribution system facilities consist of numerous equipment components that will affect or be affected by the presence of distributed generation. From a benefit perspective, the capital expense of large or high volume components, such as substation transformers, higher capacity lines, and pole infrastructure can be deferred or avoided by the use of distributed generation. Other equipment such as circuit breakers, fuses, and similar protection related a generator might adversely affect devices or limit the benefits provided by a generator. A list describing the more relevant distribution components and their purpose is provided in the Appendix.

Major Technical Services Provided by the Distribution System and Utility Distribution Company

An UDC provides a variety of services for end-use customers, including technical, operational, engineering, planning, customer interface, and administrative functions. Most all of the technical and planning functions will be affected by noticeable penetrations of distributed generation. The list below describes some of the most relevant functions that will be affected by DG, and serves as the basis for developing benefit definitions, analysis procedures, pricing mechanisms and limitations.

- Load capacity under normal conditions - The UDC ensures that the load carrying equipment throughout the distribution system can meet the peak load capacity under normal operating conditions (i.e. no major component is out of service), with reserve margin for extraordinary peak conditions.

- Load capacity under contingency conditions - The UDC ensures that the load carrying equipment throughout the distribution system can meet peak load capacity under specific contingency operating conditions, such as the loss of one or more key load carrying components.

- Operations: monitoring, control and problem solving - The UDC provides day to day monitoring of system operating conditions and equipment status; control of sectionalizing equipment, capacitors and voltage support components; and problem solving activities associated with equipment trouble and peak load periods.

- Protection and reliability (fault impact minimization) - The UDC manages the coordination, installation and maintenance of protective devices designed to minimize the extent of outages given component failures or system disturbances (storms, animals, cars).

- Voltage support - The UDC maintains voltage throughout the system within tolerances prescribed for both normal and contingency conditions, preventing them from being either too high or too low.

- Voltage regulation - The UDC may provide dynamic regulation of voltage in situations where large fluctuating loads cause voltage swings or flicker.

- Reactive power support - The UDC takes measures to limit reactive power demand on the system, such as the use of capacitors.

- Losses reduction - The UDC takes measures to limit the energy losses on the system by limiting circuit miles and strategically employing reactive power and voltage support.

- Phase balance - The UDC takes measures to prevent excessive imbalances in the loads and voltages on individual circuit phases.

- New connections - The UDC manages line extensions and the installation of service equipment required for new customer connections.

- Facility and equipment maintenance - The UDC provides routine and corrective maintenance on components at all levels of the distribution system.

- Facility and equipment upgrade, replacement or relocation - The UDC manages the replacement of equipment deteriorating from age or harsh environmental conditions; replacement or upgrade of equipment that is obsolete or incompatible with newer facilities; and the relocation of existing facilities and equipment for land-use or reliability purposes.

- Interconnection of customer generation - The UDC performs technical and administrative tasks associated with the review, approval and inspection of customer generator installations.

Bundling of Distribution Service Costs

Each of the services described in the previous section, as well as engineering, planning and administrative functions, is paid for through traditional bundling of utility costs into customer rates. Some costs are allocated directly to specific customers, such as line extensions beyond fixed distances, installation of specialized customer equipment (e.g., for power factor correction), and a portion of costs associated with DG interconnection. One of the greatest challenges for unbundling economic benefits and developing DG pricing mechanisms therefore is determining analytically how and which service costs should be unbundled. These issues are addressed in later sections of this report.

Planning Objectives and Approaches

Distribution planners strive to simultaneously meet capacity needs, maintain or improve reliability, ensure safety, increase asset utilization and minimize costs. The latter objective has become increasingly important as utility deregulation evolves and more public scrutiny is applied to management of the remaining regulated electricity functions: transmission and distribution. Planners are under more pressure from both management and regulators alike to provide a greater justification for expenditures and to find lower cost alternatives to their traditional solutions. Consequently, UDCs are re-evaluating their basic methods of planning. The future role and utilization of DG in the distribution system will be greatly affected by these evolving planning objectives and approaches.

Distribution planning presently focuses on individual geographic areas defined by the interdependence of a collection of substations. Planners evaluate their assigned areas over 3 to 5-year planning cycles, and take into account existing peak load conditions, load forecast studies, and power flow simulations that predict voltage and capacity constraints. Project needs are identified and expansion plans are developed, each project typically including one preferred and one lower-cost alternative plan. Projects are then prioritized based on the severity of need and budget targets in a given year. They compete with other capacity (major capital) projects as well as O&M projects that focus for example on outage reliability improvements. Often utilities incorporate estimates of a project's impact on customer costs, or their value of service (VOS), and develop expansion plans on the basis of minimizing the combined utility and customer costs. VOS estimates are also used to prioritize internally among competing projects, or for justification of expenditures in regulatory rate case proceedings.

The measure of a UDC's success in planning and cost containment depends not only their effective management of facilities but also on public perception, customer complaints, and no small degree of luck. Rural customers experiencing ten outages or more per year may register far fewer customer complaints than suburban customers who in a bad year experience five. Extreme temperatures in a given year may cause a major component failure and costly outage in an area scheduled one year too late for an expansion.

For a growing number of utilities, planning criteria include meeting well-defined reliability performance indicators that form the basis for financial rewards or penalties under performance-based ratemaking (PBR). These indicators include System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index

(SAIFI), and the Momentary Average Interruption Frequency Index (MAIFI). California and other states have adopted such performance incentives for investor-owned utilities, not only for system reliability, but also for safety, customer satisfaction, and call center responsiveness. Utilities are granted financial rewards if they exceed defined performance benchmarks, or alternatively are penalized if performance drops below a minimum benchmark.[94] Because PBR effectively decouples the UDC's costs from its rates, it provides greater earnings potential for UDC's that improve their load forecasting, project prioritization, and preventive maintenance.

Under the current scrutiny, load forecasting methods are often perceived as overly conservative, causing utilities to build too soon or lose out on opportunities to hedge the associated growth uncertainties with less expensive, shorter term solutions.

Distributed generation, if routinely incorporated into the area planning processes, will have a clear impact on all of these issues. Most notable is their potential ability to provide short-term capacity during years with numerous competing projects or abnormal weather, or in cases where forecasted load increases are highly uncertain. To the extent DG can be used for targeted reliability improvements, DG also has the potential to provide the UDC with low-cost solutions to meet PBR reliability benchmarks.

Distribution System Services Provided by DG

This section describes the distribution system services that DG is most capable of providing or supporting. An accompanying report discusses caveats and limitations with respect to these services, and how specific generation technologies may be more capable than others in providing benefits.[95] The distribution services include:

- Capacity support
- Contingency capacity support
- Reduction of losses
- Voltage support
- Voltage regulation
- Power factor control
- Phase balancing
- Equipment life extension

Capacity Support

Capacity support covers a wide range of cost avoidance benefits that may be provided to the distribution system by DG. This cost avoidance benefit refers particularly to the deferral or avoidance of capacity upgrades that are otherwise needed to provide reliable service to customers under normal (non-contingency) conditions. Power generated by DG on a radial system reduces the loading on facilities upstream of the point of interconnection, most importantly substation transformers and primary feeder conductors. When sited near growing loads located far from the substation, DG can reduce loading and maintain voltage on the more distant lines as well. When these facilities become loaded to the point where they are approaching their thermal operating limits, the application of DG for their benefit serves to defer or eliminate the need for installing additional capacity. The monetary benefit provided is directly related to the cost of the facilities that can be deferred, and the most benefit is gained when high-ticket items are impacted such as new substations, substation transformers, and new feeders.

Capacity support is widely acknowledged to provide the greatest economic incentive for siting DG in the distribution system. It is also one of the most straightforward benefits to analyze from an economic standpoint because it entails the avoidance or deferral of well-understood capital expenditures. The DG's cost and capacity implications are directly compared with those of the conventional facility solution. As a smaller incremental method of capacity expansion, DG provides additional economic benefits by reducing the risk of over-investment caused by uncertain load growth. Finally, distribution capacity is planned and installed to meet peak loading conditions that may occur only a few hours out of each year. DG can significantly improve the overall asset management of the UDC if it is used to provide peaking power as a supplement to the base load capabilities of transformers and lines.

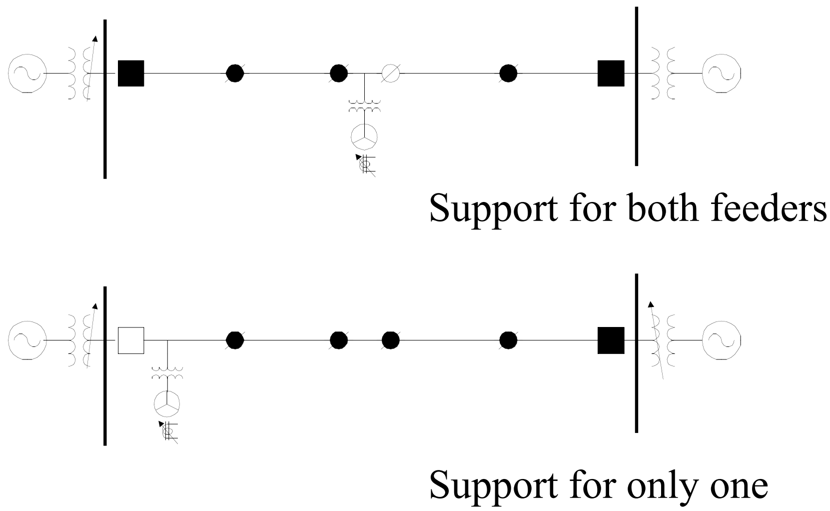
Contingency Capacity Support

DG provision of contingency capacity support is similar to capacity support in that it can defer or eliminate the need for new substation or feeder capacity. The difference is that the DG is sited where it can supplement the utility's capacity during major contingencies. Transformers and feeders are rated separately for normal conditions and contingency (emergency) conditions. Higher operating currents are permitted for transformers and lines during contingencies in order for them to pick up additional loads that would ordinarily be carried by other circuits. Thermal limitations determine how much the equipment can be overloaded and for how long before there is a risk of damage or failure. When determining the need for new capacity, distribution planners evaluate both the normal capacity of the system, and the short-term redundant capacity under key contingency scenarios.

If the contingent capacity is determined to be important enough, it may justify an expansion even if the system's capacity under normal conditions is not strained. As a result, DG's application for contingent capacity may have the same deferral impact as a normal capacity project. Depending on the nature of the particular contingency supported, DG can reduce the number of customers out of service, and/or reduce the outage duration experienced by particular segments of the feeder. In many cases, contingency capacity benefits may overlap with normal capacity support benefits, all depending on the particular needs of the distribution system.

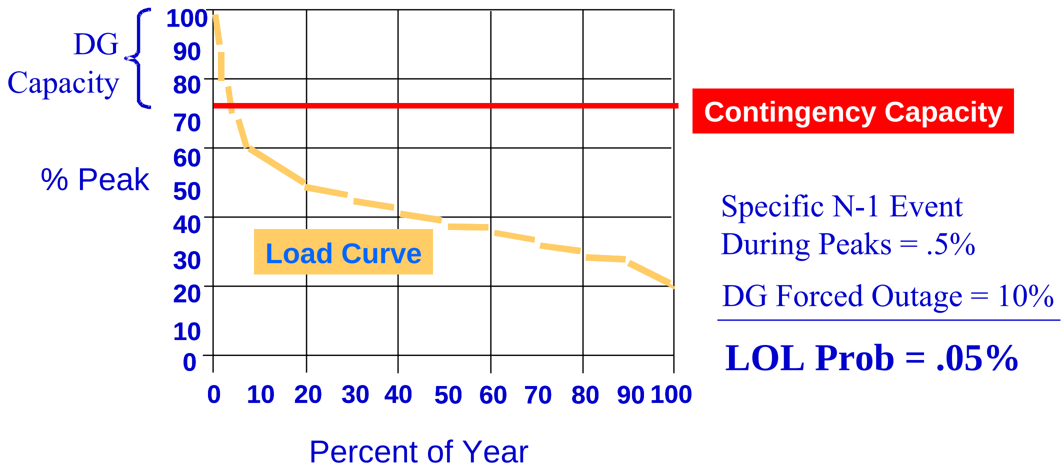
Figure 25 illustrates two examples of how DG can support the distribution system during contingencies. In both diagrams, feeders from two different substations serve an area, and contain switches (shown as small circles) for shifting segments of the load between them. The squares represent the feeder circuit breakers. If either circuit breaker were to open for some reason, the switches would be reconfigured so that the remaining substation would pick up as much of the other's load as possible. In the first case, a generator is located centrally between the two substations. Therefore, it can be used to help reduce line currents and support voltage if either of two circuit breakers operate. In the second case, the generator is located adjacent to the substation on the left, and therefore can only effectively support the system if that substation's circuit breaker opens.

Figure 25. Illustration of DG Applied for Contingency Capacity Support



One of the more contentious issues surrounding DG is its use as a substitute for traditional feeder or substation capacity during contingencies. Utility planners have argued that a generator's reliability is far less than that of a transformer or conductor, which has no moving parts, requires no fuel and far less maintenance. As such, it is not reasonable to compare their application equivalently when solving a capacity problem. However, advocates of DG such as suppliers, technology researchers and other interested parties counter this argument by noting that the contingency itself is a low probability event, and the joint probability that a generator failure would occur during the contingency event is extremely low. Figure 26 illustrates this argument. The load curve shows the proportion of the year that the distribution load is at or below the given percentage of its peak. The contingency capacity for the area is shown as roughly 75% of the peak load. Therefore, if a contingency were to occur during the roughly 4% of the year in which the loads exceed the contingency capacity, the system would be unable to serve the remaining load. In this example, the probability of the contingency event occurring during the peak conditions is 0.5%. Therefore, even with a relatively high generator forced outage rate of 10%, the joint probability of a loss of load (LOL) condition has been reduced ten-fold given the generator application.

Figure 26. Illustration of DG's Impact on Improving Distribution Contingency Capacity



Losses Reduction

UDCs take measures to limit energy losses on their systems. Reduced losses improve the overall efficiency of the distribution system and require the UDC to purchase less energy to meet the same customer demand. Upgrading conductors on a long circuit, or providing reactive power support in an area where reactive power losses dominate the problem usually solve cases where high losses are a problem. DG can also reduce system losses by reducing the current flow from the transmission system through the transformers and conductors on the distribution system. Because losses are proportional to the square of the current load, DG's effect on reducing losses is most pronounced during peak loading periods. The presence of DG in the right locations can possibly defer or eliminate the need to re-conductor specific feeder segments. The effect of DG on reducing losses in the system is easily quantifiable in energy savings to the utility, and some limited capital avoidance.

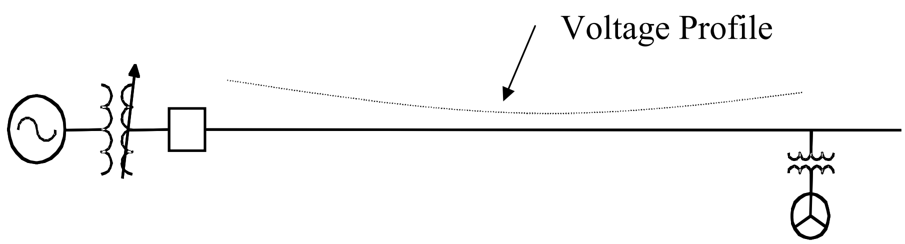
A secondary benefit that DG-based loss reduction provides to the UDC is the reduction of the UDC's total installed capacity as seen by the transmission system and the system operator. Depending on the methods used to determine transmission capacity payments and ancillary services charges, the incremental loss improvements provided by DG may help reduce the UDC's payment for these charges.

Voltage Support

A UDC defines criteria for maintaining voltage throughout the system within prescribed tolerances, and will take measures to prevent them from being either too high or too low under normal or contingency conditions. The greater concern is typically keeping the voltage above minimum limits, because voltage drops are more precipitous during peak load periods. Conventional measures used to provide voltage support include the installation of voltage regulators, which are essentially series transformers with variable output settings, or, capacitors, boosters, and in some cases upgraded line segments.[96] Reactive power support has a powerful impact on supporting voltage, as there is a more direct relationship between voltage and reactive power flow than with real power flow. For that reason, capacitors are often preferred over regulators.

DG can help support voltage in areas of the distribution system that experience significant drops at high loads. In most cases voltage support means raising the voltage in the area of the DG site for the particular load periods in which it is needed. Voltage support is provided by injecting power into the system at the DG site, thereby reducing the current and corresponding voltage drop from the substation to the area. This concept is illustrated in Figure 27 below. The generator is sited on the feeder at a distance from the substation. The dotted line is representative of the voltage magnitude at points along the line. Without the generator, the voltage would continue to decrease, possibly dropping below the allowable minimum. With the generator however, the voltage is supported limiting current and therefore the impedance related drop.

Figure 27. DG Used to Improve Voltage Conditions on a Distribution Feeder



With appropriate technology, voltage support can be provided by DG through reactive power injection as well. To the extent that DG can provide voltage support functions to a UDC, it can defer or eliminate the need for the UDC to purchase and install the conventional equipment, such as capacitors. Certain types of DG can theoretically provide a smoother, more responsive control of the voltage than capacitors. However, to do this properly will generally require external control signals. The economic value of voltage support will often overlap with both capacity and power factor support benefits.

Voltage Regulation

Voltage regulation refers to controlling periodic swings of the voltage on a particular part of the system caused by larger fluctuating loads. UDCs typically install voltage regulators with automatic tap changing mechanisms to solve a voltage regulation issue. DG can potentially regulate voltage in such situations by balancing the fluctuating loads with fluctuating generation output. If properly sized, DG technologies that are capable of reactive power control can dampen these voltage swings even while maintaining a constant real power output. An effective DG application would improve utility operations, potentially improve the life of voltage regulators by reducing tap changing operations, and possibly eliminate the need for purchasing the voltage regulator equipment altogether.

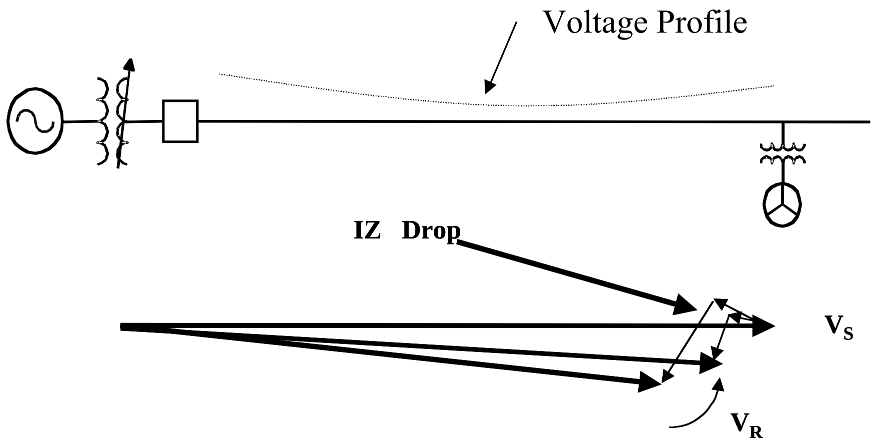
Power Factor Control

Power factor control most often refers to the injection of reactive power into the distribution system to balance the reactive power demand from inductive loads, motor loads, and the inherent inductance in the power delivery components. A high reactive power demand results in higher current demand for the same amount of real power delivered. The higher reactive power demand reduces the system's power factor, which is the standard measure for real and reactive power balance.[97] The UDC will take measures to limit reactive power demand on the system, such as with the use of capacitors, and generally requires that customer loads do not have power factors below 80%.

The result of improved reactive power flows (or improved power factor) is less current and apparent energy required from the transmission system, less current (and therefore losses) on the distribution components, and better control of system voltage. DG can help balance reactive power flows on the distribution system with both real and reactive power injection. Real power injection reduces current in the conductors, which is a major source of reactive power demand. As mentioned before, DG technologies with reactive power support capability clearly can provide this function to a greater effect than that gained by only real power generation. Because of the interrelationship between voltage and power factor control, the benefits associated with each will often overlap.

Figure 28 shows the same feeder used to illustrate the voltage support benefit, but in this case mostly a poor power factor load on the system causes the voltage drop. If the DG unit supplies reactive power to support the power factor, it will reduce the system's apparent energy, currents and losses. The vector diagram illustrates the improved local voltage V_R increasing and moving closer in phase to the substation source voltage V_S, as a result of the generator's effective reduction of the reactive impedance Z. The IZ drop shown is the drop between the source and local voltage caused by the reactive impedance.

Figure 28. DG Used to Improve Power Factor Conditions on a Distribution Feeder



Phase Balancing

Phase imbalance is caused by among other things, an unequal distribution of single-phase loads on the three-phase system. Resulting voltage imbalances cause operating inefficiencies in equipment, and excessive currents in certain transformers and neutral circuits.

Some inverter-based DG technologies can help to alleviate this problem by controlling their phase outputs to offset the imbalances caused by other loads. This application will require more mature control and monitoring protocols than are normally applied today, and would therefore only be implemented when DG penetrations are significant enough to justify the development costs.

Equipment Life Extension

The theoretical impact of loading on the life of equipment such as the substation transformers, regulators, and feeder conductors is well documented and can be estimated using software algorithms. For substation transformers, several software programs incorporate algorithms defined in ANSI/IEEE Standard C57. This standard provides a guide for transformer loading based on thermal limits that impact the accelerated aging of coil insulation. Internal oil and "hot spot" temperatures are determined by the transformer load and ambient temperature over time, as well as size and design characteristics. Loading that causes the calculated loss of life to exceed 0.037% in a single day during normal operation is considered to cause an accelerated loss of life (given a 40-year life expectancy). For emergency conditions, it is typical for utilities to limit loading such that the loss of life never exceeds 1% over a single 24-hour period.

Therefore, measures taken to prevent daily loss of life from exceeding the normal and emergency limits are theoretically providing an economic value equal to the costs associated with the transformer's otherwise premature replacement.

The problem with using this type of cost function is that it incorrectly assumes a utility bases its equipment replacement decisions on an accurate account of historical loading data. Furthermore, the ANSI C57 guide itself acknowledges that it is not possible to predict with any real degree of accuracy the length of a transformer's life. As such, it is not likely that DG owners can successfully pursue payments based on this type of cost function.

Many utilities merely use the ANSI guide to define loading limits for their particular load and ambient conditions, and make expansion planning decisions to prevent loads from exceeding those limits. DG's value in these cases is tied back to capacity deferral - by limiting thermal overloads on the transformer, they are deferring expansion costs, not replacement costs.

Where DG can selectively provide value for equipment life extension is with aging facilities. Utilities regularly face the need to replace equipment that is deteriorating from age or harsh environmental conditions. By extension, there is also the occasional need to replace or upgrade equipment that is obsolete or incompatible with newer facilities.

Projects to replace old and/or weakened facilities compete with capacity expansion projects for limited capital budgets, and often lose. However, an important factor (of many) that influences the urgency of a replacement project is the equipment loading. Lightly loaded systems experiencing little growth are less likely to be replaced as quickly as similarly situated systems operating near their ratings. If DG is used to keep loading levels on these facilities below a predefined de-rated value, they may reasonably be credited for the deferral of replacement costs.

Technical Factors Influencing DG Service Pricing Strategies

Later sections of this report focus on various pricing strategies for the distribution benefits provided by DG. These strategies will be developed in part by categorizing the technical services by the nature of benefits they provide. The categorizations include the type of expenditure avoided by the DG installation, the length of time the benefit is realized, the availability of information needed to quantify a potential benefit, and the ability to validate whether a benefit is realized.

Nature of Economic Benefits

DG's greatest potential impact is in the reduction of UDC capital expenditures. This is particularly true for capacity support and replacement services, where the DG is used to delay or substitute a major capital expense. The operational services such as voltage support, voltage regulation, power factor support, and even losses reduction can directly reduce capital expenditures, as the DG is a substitute for new capacitors and regulators.

Operational expenditures can be reduced as well in losses reduction, voltage support, voltage regulation and power factor support applications. The clearest example of this is the DG's ability to reduce losses, thereby saving the UDC additional energy costs and to a smaller degree, ancillary service allocation costs. In voltage support applications, DG can reduce the number of voltage regulator tap changing operations, and therefore lengthen their corresponding maintenance intervals by UDC operators. The impact is similar for power factor applications, as DG can reduce the need to switch capacitors on and off under changing load conditions.

Short and Long Term Service Benefits

Benefit valuation will be highly dependent on the length of time a DG provides a particular benefit. The most illustrative example of this is capacity support and replacement applications that provide a fixed term capital deferral benefit. If a DG installation enables the UDC to defer a planned upgrade for two years, only the deferral savings will value the benefit. Once the capacity expansion has taken place, the DG unit provides no value from a pure capacity needs perspective. These applications can however provide longer-term expenditure benefits if they either eliminate the need for an expansion or replacement altogether, or if they allow the utility to select a smaller, less expensive expansion plan to supplement the DG capacity.

The other applications result in benefits that is more indefinite in nature. A DG unit dispatched to improve voltage or power factor conditions will be able to provide these benefits indefinitely. However, major capacity expansions in the future that alter the system configuration will likely reduce the need for DG in these applications. Therefore pricing strategies will need to address alternative ways that payment contracts can expire.

Since the length of time that DG may provide benefits to the UDC varies for different applications and different areas there isn't a single time horizon that would be appropriate to estimate avoided costs. Therefore, evaluation of benefits (or avoided costs) does not fall easily into a 'short-run' or 'long-run' perspective, but should represent the underlying term for the benefits and the duration of the contract with the generator.

Planning and Operating Information

Benefit allocation is highly dependent on the availability and quality of distribution system cost and planning information. Models of various quality and depth of detail are used by UDCs to develop a picture of their system constraints. Given these models, it is not difficult to estimate the impact of a specifically sited generator on the system, however the benefits determined by the model are only as accurate as the assumptions and data compiled to analyze them. It is therefore important that pricing mechanisms put priority on benefits that are more accurately forecasted.

The ability to monitor and verify benefits provided by installed systems is equally difficult with the existing state of UDC data monitoring and communication capabilities. Distribution operators rarely have real-time remote access to operating information, even at substations. Recorded information is often available at substations, but there is substantial variation among utilities with respect to monitoring capabilities. However, it is important that the evolving monitoring and control technologies be implemented more broadly for DG benefits to be applied and validated properly. Any additional monitoring costs required by the utility to implement DG solutions should be netted against DG benefits for cost / benefit analysis.

Pricing Distribution Services Provided by DG

As discussed in the previous section, DG is technically capable of several distribution system services. The purpose of this section is to discuss how UDCs should acquire these services from DG owners/operators, with a focus on how these services should be priced. When a utility purchases distribution services from a distributed generator, it will ultimately result in an agreement or contract between the distribution owner and the DG owner. This contract will specify the important attributes of what the DG must provide, including how much energy or capacity the generator must provide, when it must be provided or how it will be dispatched, as well as the price it will be paid. This section discusses the important terms in the contract between the utility and the DG provider, and the different methods that can be used to price these distribution services.

The services provided by DG are fundamentally *inputs* for the delivery of electricity of suitable quality, or *substitutes* for a service provided by the utility. Traditionally, these services are self-provided by utilities, usually obtained by means of capacitors for power factor correction, voltage regulators or switched-tap transformers for voltage support, or capacity expansion for reducing losses and enhancing reliability, for example. The previous section discussed the technical capability of DG to provide these services in lieu of traditional utility solutions. This section discusses the pricing mechanisms and important contractual terms and conditions that will be needed to insure fair treatment of DG providers and efficient, reliable and cost effective provision of distribution services.

Contract Structure

Any agreement between the UDC and a DG owner for distribution services will result in a contract in some form. That contract may be a tariff approved by the appropriate regulator, it may be a standardized contract the utility uses to procure a DG service when the need arises, or it may be a custom contract between the utility and the DG owner to procure services. In all cases, many of the key contract provisions will be the same and must be developed to appropriately implement third party provision of DG services. This section describes the common types of contracts, and the important contract terms.

Contract Types

There are three main types of contracts that could be used by a UDC to purchase distribution services from a third party DG owner. From most general to the most specific, these are:

- Regulated tariffs,
- Standardized contracts, and
- Custom contracts.

Regulated Tariff

In general, the broadest type of contract that is still appropriate for procurement of DG services in a particular situation should be used. This reduces transaction cost by reducing the time to draft a contract by the utility, reducing the time required to educate potential bidders since they are more likely to be familiar with the contract terms, and reducing overhead costs on DG owners/operators to respond to UDC requests for service. To facilitate ease of implementation, the ideal contract form would be an approved tariff that contains all the contract details of the procurement, including the price and DG operational and contractual requirements, in advance. However, in many cases the details of what the DG would have to provide are local-area and time specific, and the price (or value to the UDC) is situation dependent as well. In such cases, a modified tariff that reflects the time and location-specific aspects of the value of service, or another contract structure, would be more appropriate.

Standardized Contract

A standardized utility contract would include most of the contract terms, but leave some details to be filled out at the time of the procurement. For example, all details except price and the number of hours of DG dispatch could be posted, in advance, in a contract that was applicable across a UDC service area. When the UDC identifies a particular problem in the distribution system, the contract can be quickly completed by filling in these last items appropriately for the given area and situation. The standardization of the contract terms is an advantage because DG owners only have to understand one contract for all applications, and it is only the changed features that must be reviewed before agreeing to the contract.

Custom Contract

Some services that DG can provide will be so specific to a particular situation that it is impossible to structure the contract before the distribution utility identifies the problem. In this case, the utility would have to develop and tailor a specific contract, and educate potential bidders on the specific proposal for procurement of services from DG. Of the three types of contract, this is the most time-consuming and difficult to implement, and probably only makes sense when large transaction costs are justified by the value of the DG services to be provided.

Key Contract Terms

Any contract for the provision of DG distribution services, either a tariff, standardized contract, or custom contract, will require several key contract terms in addition to price that will define terms and conditions under which service is to be provided. These terms include:

- Quantity of services delivered;
- Payment schedule;
- Duration of contract;
- Delivery location; and
- Other terms related to legal and financial responsibilities.

These contract terms are discussed in more detail below. Pricing for distribution services is discussed in detail in the next section.

Quantity

The amount of capacity relief, loss reduction, voltage support, or other distribution service that DG can provide is determined by the total installed size of the DG. In most cases, the level of value, and the incentive payment to a DG owner, will depend in part on the size of the generator or generators.

Depending on the UDC's requirements, the DG services can often be provided by one large generator, or a group of small generators. For contingency support, deferral capacity, as well as other distribution services, this complicates contracting since more than one DG owner may be required to perform in a coordinated manner when required for system support. If not enough load is generated in aggregate among the DG owners, or not enough load participates in providing capacity relief in an area, the utility may have to spend money to correct the problem itself, and there will be no value to those DG owners willing to participate. Therefore, the utility may not be able to enter into any contracts until they find enough DG owners that will together provide enough load reduction. For example, in the California ISO's RFP for capacity relief in Tri-Valley, a total of 175MW of load relief was required to defer a planned transmission project. The ISO received four responses to the RFP. If the ISO had decided to move ahead with the project, it would have had to contract with all four bidders to meet its capability requirement.

The other potential difficulty with having many DG owners jointly providing a service is the added transaction costs of administering many contracts. Managing fifty 100 kW contracts to achieve 5 MW of capacity relief can be costly. This problem can be solved with a minimum bid capacity provision. To comply with such requirements, however, small generators or curtailable load could aggregate and submit a joint response.

Payment scheme

Fixed incentive vs. Variable incentive

The key aspect to developing a payment scheme is to match the value being provided with the timing and formulation of the payments. The appropriate payment scheme will vary depending on the type of DG service being provided. Some types of services, such as capacity deferral, may be best implemented through a fixed incentive payment that does not vary with operational characteristics. There is a value of having the capacity available regardless of how often it is required. Other services, such as loss reduction, are best structured as a variable charge depending on when the DG is in operation.

Duration

Open-ended vs. Fixed Duration

Like the payment scheme, the duration of a contract should match the duration of the benefits. Some distribution benefits of DG exist for a short time-period, and others last indefinitely. For example, on a capacity project deferral application, once the installed amount of DG can no longer delay the project and the utility builds, the DG capacity provides little or no value to the UDC and the contract should end. On the other hand, cost-effective development of DG to provide distribution services will require that DG developers have some certainty of contract length to effectively finance their projects. Therefore, if open-ended contracts are not possible, the UDC needs to determine the period that the DG provides value to the UDC system to develop the appropriate contract term.

Delivery Location

The ability of DG to provide any of the distribution services, except perhaps loss reduction, depends on where in the system DG sources are placed. One point on the system that is at or near a capacity limit may provide valuable deferral benefits, while another point may have excess capacity and not benefit from DG load relief. Identification of the point on the system where the DG is connected is extremely important. Having DG provide distribution services at a particular point will require the location-specific signals from the UDC.

Other Terms

In addition to these contract terms, there are many other terms that will be required, but are beyond the scope of this task on distribution service pricing. These items include credit, compliance standards and penalties, legal jurisdiction, confidentiality, and other terms.

Pricing Mechanisms

There are three main pricing mechanisms that can be used to set the contract price for distribution services provided by DG. These are a 'Price Posting' method where the utility offers a complete contract and contract price for the services, an 'RFP / Auction' process where the utility specifies all the contract terms and potential suppliers bid in a competitive process, and a 'Bilateral' process where only one seller is capable of providing the service and a mutually agreeable contract is negotiated. A hybrid pricing structure is possible that blends elements of each approach, for example a UDC may use an auction approach to establish the price in their negotiation for a bilateral contract with a single seller. However, for clarity and the purposes of discussion these categories will be useful. Figure 29 depicts the major steps in each method and is described in more detail below.

Figure 29. Comparison of the Three Main Pricing Mechanisms

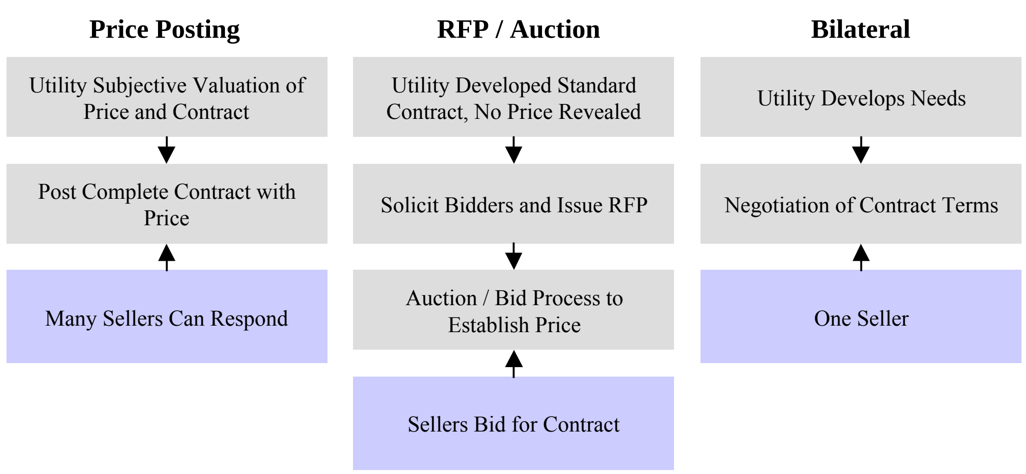


Table 32 provides a high level summary of the benefits and drawbacks of each of these pricing mechanisms.

Table 32. Summary of Pricing Mechanisms

Pricing Mechanism	Summary Pros and Cons
Price Posting	Pros: Lowest transaction cost, implemented in a standard tariff
	Cons: Open to cherry picking, little information revelation, needs to be standardized across tariff applicability, open-ended.
Price Auction/RFP	Pros: Competitive prices are revealed, can be customized to each application, closed-ended.
	Cons: Long lead time required, high transaction costs
Bilateral Negotiation	Pros: Can lead to reduced system costs
	Cons: Price not competitively determined or cost based.

Price Posting

Price posting has the least transaction costs of any of the pricing mechanisms. With this approach, a utility would file a tariff that offers a credit or payment for certain DG applications. The tariff would include all of the contract terms, and the level of incentive. DG owners could evaluate whether they would like to provide the service at the posted price and, if so, could elect to participate in the tariff. This is the best approach when the value of benefit for the DG service is relatively similar across a utility service area (or in areas where the tariff is applicable), and when there are many sellers of the service because transaction costs are reduced significantly.

The first problem with price posting occurs when a single tariff is used over several regions and the value of the DG service is not similar across all these areas. In this case, it is very difficult to set a price for the service. In high value areas, the incentive will not be high enough, and efficiency improving applications will be lost. In low value areas, the incentive will be too high and could lead to increasing the total costs on the system. For applications when the cost of providing DG is low in low value areas, price posting can lead to 'cherry picking' when only the "easy" installations of DG that provide little value are implemented. These problems can be minimized by setting uniform prices across areas with uniform value, which will have the effect of bringing DG payments closer to actual avoided costs.

The second problem with price posting is how to set the price level. If the utility sets the price of the service equal to the avoided cost of the utility solution, then there is no decrease in the total costs of the system (and possibly an increase if the transaction and monitoring costs are not properly accounted for). If the utility sets the price at, for example, 20% below avoided cost then there may be profitable applications, but this level may be too high (DG owners would have been willing to provide the service at a lower incentive level, further reducing UDC costs) or too low (too few DG owners participate, and cost saving applications are missed). Therefore, setting the price may lead to over- and under-supply conditions of the DG services. However, in cases when the value of the service, and the costs of providing it, are similar across the service area, these problems are minimized. The UDC will be able to estimate what the incentive payment level is needed to interest DG owners, and the reduced transaction costs from avoiding more complex auctions or negotiations probably outweigh such inefficiencies.

In the context of Performance Based Ratemaking (PBR), the 'gap' between the avoided cost and the DG incentive payment can be shared between the utility and ratepayers in terms of lower rates. A PBR designed to share the benefits of lowering system costs will provide the utility with more incentive to seek out cost-effective distribution service applications of DG. UDC incentives and regulatory structure are discussed in more detail in 'Key Issues and Drivers' section.

RFP / Auction

Competitive procurement of DG services through an RFP or auction process has been by far the most common pricing mechanism used for transmission level services. In addition to system operators' regular procurement of transmission ancillary services in many jurisdictions, a number of utilities have issued RFPs for capacity to defer transmission and sub-transmission upgrades. These include the California ISO's RFP for the Tri-Valley area and ConEdison's RFP for generation capacity. These RFPs took significant effort and preparation time, but could have potentially deferred significant investments in the tens and hundreds of millions of dollars.

To issue an RFP, the distribution company develops a proposed contract specifying the key contract terms and then solicits DG owners to bid to provide capacity under this contract. Those DG owners that responded to the offer with the lowest price are selected. The advantage of competitive procurement for these large projects is the use of a competitive price for the services provided. As illustrated in the box below, auction-style pricing mechanisms can be combined with a tariff contract form to provide a relatively low transaction cost method of procuring services from DG and loads.

Bilateral

The bilateral pricing mechanism is simply a direct negotiation of price and other contract terms between the utility and the DG service provider. This becomes necessary when, for example, only one DG owner on the system can provide the particular DG service that is required. The problem with the bilateral agreement approach is that the price is not developed through a competitive process, but is the result of the negotiation. This can result in paying a price to the DG owner that is higher than they would otherwise accept. This market position is reduced somewhat by the ability of the utility to build their own solution to the problem. Despite the potential for higher than competitive prices, this approach can still lead to reduced system costs.

Rate Options for Peak Capacity Relief

In 1998 Detroit Edison received approval from the Michigan Public Service Commission (MPSC) to implement three new electric rate options for large customers that would help the utility manage peak customer demand.

These rates options incorporated opportunities for onsite generation and demand management, including:

- "A program for large customers who have onsite generating capability of 250 kilowatts or more that makes it attractive for them to operate their backup generators at Detroit Edison's request to offset the needs of their facilities during peak use periods.
- A program, which allows large customers who have the ability to reduce electricity use on request to place, bids with Detroit Edison to voluntarily release their electrical capacity back to the utility. Customers will place bids in cents per kilowatt-hour for how much money they will accept in payment for reducing their electric load. Detroit Edison will ask customers to release capacity starting with the lowest bidders."[98]

Key Issues and Drivers

There are several important issues that impact the pricing of DG distribution services. These issues can be broadly categorized by (1) attributes of the product or service being provided, (2) characteristics of the market for those services, (3) the incentives that exist for the utility and providers, (4) risks faced by the various potential participants, and (5) practical implementation concerns. This section provides a concise discussion of the main drivers in each of these categories and their critical implications for pricing mechanisms.

Service Attributes

The two key attributes of any service that DG can provide are *scale* and *uniformity*. "Scale" denotes just how large the problem (or market) is, and comprises how many transactions are needed, how big they are, how long they are needed. A large-scale problem that requires numerous small transactions is better suited for a posted tariff. Projects with only a few fairly potential solutions are better suited for an RFP or bilateral contract. "Uniformity" denotes homogeneity over space and time (is the need and value about the same from one place to another or from year to year?) as well as stability (is the need constant or is it sporadic?). A service may be non-uniform, but still capable of being standardized if it is easily characterized, such as a service needed only during weekday summer peak periods or with different needs or values by location. More uniformity simplifies posted tariffs as well as the RFP process. An RFP approach is favored as the service in question becomes less homogeneous because of the increased complexity and associated costs of posted tariffs, especially if the services (and possibly the prices) change sporadically with time or are contingent on system loading in complex ways.

Market Characteristics

The primary relevant market characteristic influencing the best pricing approach is the number of potential suppliers. The more suppliers, the lower the risk of collusion and the higher the likelihood that the auction process will obtain a competitive result. If there are a large number of actual suppliers (as opposed to a few suppliers selected from a large population of bidders) a low-transaction cost pricing method such as a posted tariff offers efficiency benefits.

The second critical market issue is information revelation, which are partially a market characteristic and partially a procurement and contract design concern. Both influence the manner in which DG owners, the utility, and regulators learn about each other's costs, technology and preferences over time. For obvious competitive advantage concerns, neither the UDC nor DG suppliers want to reveal their own costs. A posted tariff announces that the utility's best estimate of its cost, and the responses. Responses to a posted tariff reveal only the quantities provided – and could resulted in over or under-supply. A fixed-price and fixed-quantity posting can prevent over-supply but does not address under-supply. A bilateral contract favors the entity with the greatest negotiating power (and skill). Bidding introduces complex interactions between auction rules, information revelation, and various incentives that are further elaborated below.

Furthermore, information available to potential market participants is uncertain and asymmetric: utilities and DG owners have some imperfect estimate of each other's costs and values (and regulators have their own imperfect information), and no one's information is exactly the same. Asymmetric information allows a regulated firm to enjoy a rent[99] (an above-normal rate of return), and the added complexity of asymmetric information at the second level of transactions between the utility and DG service providers compounds this issue. The means by which information is revealed affects the degree of asymmetry and uncertainty for the market participants. Better information for all parties reduces excess costs caused by rent-seeking behavior.

Finally, the market for services that DG can provide to the distribution utility is in turn influenced by the value that the distribution customers place on those services. What role should customer value of service (VOS) take in pricing these services? For those services that are reflected directly in existing tariffs, the price is already established (such as power factor charges or losses). For others, the link between the specific services the utility requires (reactive power, voltage support, capacity deferral, etc.) and what customer's value (energy, reliability, quality) is more tenuous. Customer VOS maybe useful for prioritizing and in some cases justifying projects[100], but is not well suited for establishing a market price or even a ceiling or floor for the services themselves. It is somewhat like setting the price for flour, water, yeast, ovens and energy based on the value placed on bread (or in some instances how the bread tastes). Customer VOS also has its own issues with accuracy of VOS estimates and complex fairness issues due to variations in value between customer classes.

Incentives

In order to create an environment where the DG distribution service transactions actually take place, the pricing, terms, and market rules should be *incentive compatible*: the utility (the ultimate consumer) and DG provider must both profit (or at least be no worse off) by participating. Any pricing mechanism can create perverse incentives, resulting in an outcome opposite of the intent, and can also induce economic inefficiencies by introducing what appears to be competition on the surface, but in reality introduces distortions and cross-subsidies that were absent under utility self-provision of services.

Utilities and DG distribution service providers are motivated to maximize their own net benefits, given the information at hand, regulatory limitations, and the rules governing service transactions. Regulators must balance several interests, including total social welfare (efficiency), equity (e.g. avoiding cross-subsidies), cost effectiveness, customer concerns (e.g. quality and end-use price), economic development, continued improvement and innovation, and fairness. They also want to accomplish their objectives with the least amount of effort and interference with markets as possible.

Most distribution system companies have been operating under long established Cost-Of-Service Regulation (COSR), in which the prices they charge customers are set to recover all of their costs (plus a reasonable return on investment of investor-owned companies). COSR can lead to over-investment in capital (the well-known Averch-Johnson effect[101]), and provides little incentive to innovate to drive down costs, except through fear of expenditures being deemed "imprudent". This incentive problem remains when evaluating unbundled costs.

Alternatively, Performance Based Ratemaking (PBR) does not regulate cost but provides incentives to improve performance, operate efficiently, and make business decisions on economic grounds, while reducing regulatory burden. This may take the form of a price cap or revenue cap and can incorporate profit sharing, benchmarking, and program specific penalties and rewards[102]. PBR provides a means by which cost savings can be shared between customers, distribution companies, and distribution service providers, and is well suited for targeting specific services or performance goals.

Both COSR and PBR are forms of incentive regulation. The utility behavior the regulator wishes to encourage drives the design of regulatory review, along with the interests of various stakeholders and interveners. Cost-based and performance-based regulation are not two distinct methods, but rather ends of a spectrum determined by factors such as: length of time between rate cases; cost items passed directly through to rates on a dollar-for-dollar basis (“Z” factors); and flexibility in pricing. Strict regulation of fixed-cost allocation among rate classes discourages efficient pricing under performance-based regulation.

Price levels, auction rules and contract terms need to grapple with these fundamental driving forces in order to appropriately guide the incentives that they establish. Establishing fair prices with which providers are fairly compensated and utilities reduce their costs requires that some information about costs and capabilities will be revealed in the process. Neither firm wants to “tip their hand”, thereby losing valuable negotiation power. The rules should be established to provide the necessary information without destroying the incentive to participate.

Two incentive issues arise from informational limitations: moral hazard and adverse selection. The classic moral hazard problem example is car insurance, wherein purchasers of insurance drive less carefully knowing that they are covered. When one party has information about variables that they control, they then have potential to extract extra rents. A relevant hypothetical case might be a utility that offers a reactive power contract contingent on system power factor, inducing investment by a service provider in a DG unit with such capability, only to have the local power factor changed later by the utility at their discretion (for example by a load transfer or substation reconfiguration). Adverse selection arises from private information known before a contract is executed - "when one party to a bargain has private information about something that affects the other's net benefit from the contract and when only those whose private information implies that the contract will be especially disadvantageous for the other to agree to a contract"[103]. An adverse selection example could be if a DG owner offering voltage support knows that his technology could cause harmonic distortion problems not covered in the contract terms.

DG service providers have an incentive to obtain the highest possible price, and therefore overstate costs. Utilities who enter into agreements have an incentive to push the price as low as possible, as long as there is some gain for them in providing service at lower cost. In fact, they may be motivated to push the price ridiculously low so as to guarantee little or not participation by DG providers, reverting to self-provision with costs known only to the utility. With a fixed price for services, there is an incentive for DG owners to reduce costs. If the price is set by regulatory oversight of cost, they have an incentive to pad their costs. Even the *possibility* of regulatory review can reduce the incentive to reduce actual costs, anticipating what is known as "ratcheting", or the process of reducing allowed prices as costs are discovered by regulators to be lower than they had thought (ratcheting also applies to expected performance standards, penalizing good performance by raising the standard when providers perform better than expected). Ratcheting is a common problem with repeated relationship under short-term contracts, and can be averted to some degree with longer-term contracts.

Pricing rules must also guard against collusion, which is essentially another form of private information—one in which the potential service providers share information with each other (whether explicitly or implicitly) but not with regulators or the utility. A first-price auction (where all successful bidders receive the price of the marginal bidder) with a fairly low price cap is a good example of this problem, as experienced recently in the California PX market for bulk power. This issue is more prevalent in frequently repeated auctions, but can also be a major issue in single-time RFP where potential providers know more about each other's costs than the utility or regulators do. Posted tariffs do not suffer from collusion problems.

Potential adverse outcomes from inadequate incentives include:

1. *Rent extraction*. Either DG distribution service providers or the utility realizes an above normal profit at the expense of the other party and ultimately also at the expense of consumers.
2. *Inefficiencies*. Other welfare losses may result from over- or under-supply, due to prices that over- or under-state the social value of the services being provided.

3. *Cream-skimming*. Also referred to as cherry-picking and other predatory-pricing terms, uniform service prices could lead to DG owners offering services only where they are the cheapest to provide, leaving the high-cost location or times to the utility. Avoiding this pitfall requires location and time-differentiated prices.
4. *Uneconomic bypass*. Customers could opt to self-provide services the utility has traditionally offered, (or to contract to a third party). This bypass is uneconomic if the utility is really the least-cost provider. Such a situation can arise, for example, if prices end-use customers pay are higher than the price offered for third party services. Bypass can lead to rate increases for the remaining customers. Not all bypasses is uneconomic, though, as DG-provided services that cost less than utility-provided services would be an improvement.
5. *Lack of participation*. Under pricing could lead to inadequate incentive to participate, leaving potential costs savings unrealized.
6. *Interacting service problems*. Some services provided as a result of one incentive could cause problems elsewhere. For example, high voltages or harmonic distortion in distribution systems could result from over-correction for voltage control of reactive power from cycling small generators.

Contracts based on system performance are more prone to the incentive problems discussed above as compared to provision of specific services on a unit price basis. An RFP that stipulates, "manage voltage at point X between V1 and V2" has several control and informational issues compared to "provide W units (kvars) of leading power at point X during the hours of Y and when system load exceeds Z".

Real-time posting of either physical units (resource directive) or service prices (price directive) could potentially accomplish many of the service provision goals of the utility while maintaining system stability, but requires more infrastructure and effort than simpler pricing and contractual approaches such as load-dependent, time-dependent, or fixed price arrangements.

In general, posted tariffs with a cap on quantity provided might suffer from some potential loss in social welfare, but limit oversupply and require little or no knowledge of provider costs. The auction/RFP approach is open to collusion and most of the asymmetric information issues listed above, but, if carefully crafted, can reveal more information for regulators for achieving increases in overall economic efficiency. The bilateral contract is open to the same problems, and tends to favor the firm with the most negotiation strength.

Risk

Prices and terms need to be provided so that there is a reasonable degree of certainty that the DG owner will be fairly compensated for their investment. Without guarantees, the process will need to be adjusted upward to reflect the added risk. Likewise, utilities are concerned about who is in control. The utility is responsible for providing the services that they will now have contracted for, so they want to control as much of the transaction as well as the operation of the DG unit as they can. This adds to the certainty that the services will be provided as needed with the quality specified, and is compounded by the possibility of default or bankruptcy on the part of the DG contractor. These concerns can be addressed adequately using contract terms, but the added uncertainty and risk being assumed by the UDC reduces the price that the UDC should pay for services provided by DG.

Implementation

A key practical element of outsourcing any utility service is that paying incentives equal to avoided cost does not reduce UDC costs (and by extension customer rates) and may in fact increase costs and rates if transaction costs and increased risk on the part of the utility are not incorporated into the avoided cost calculation. However, paying larger incentives provides the greatest stimulus for developing DG markets and the associated technologies. Therefore, a balance of incentives and cost reductions must be reached to achieve both goals. Furthermore, if the incentives reflect time- and location-dependent avoided or marginal costs, then DG owners will be encouraged to site new installations where it is most beneficial, avoiding cream skimming and improving asset utilization.

The appropriate pricing mechanism depends strongly on the magnitude of the transaction cost relative to the overall cost. Establishing posted tariffs has a large initial effort, but generally small follow-on costs, as long as the measurement, compliance, and settlement costs are small. This pattern is similarly true for periodic auctions for services that are similar each time.

Another important consideration is to avoid time delays from too complicated a pricing approach. Many distribution system activities have tight schedules and relatively short lead time, so that by the time a complex process has cycled through, the utility engineers may well have gone ahead and fixed the problem (and eliminated the need) because they could not wait. This issue persists throughout most distribution systems because the needs arise quickly relative to the response time for addressing those needs. This short-lead-time situation favors posted tariffs that require no bidding and negotiation cycle, or at least standardization of processes, criteria and terms for specific services.

Distribution Service Pricing Proposal

With this background on the various contract terms and pricing mechanisms, this section proposes an approach for pricing each type of distribution service, highlighting the benefits of each approach as well as the potential pitfalls.

Distribution services fall into three fundamental categories: (1) those that primarily substitute or defer investment in major capital assets (such as capacity), (2) those that provide a power quality control function (such as voltage support), and (3) those that substitute for energy purchases (such as losses). Table 33 below summarizes each specific distribution service provided by DG, the benefits that accrue as a result of that service, the associated service category, and a qualitative assessment of the magnitude of the potential contribution relative to the total DG services market. The actual realized scale of contribution is highly situation-dependent; reflecting both time and location-specific costs and benefits.

Table 33. Distribution Services Summary

Service	Benefit	Category	Relative Impact/Merit
Normal Capacity	Capacity deferral or substitution	Asset	High
Contingent Capacity	Substitute reserves or redundancy	Asset	Med-High
Replacement	Equipment life extension	Asset	Low-Med
Voltage Support	Quality control	Quality	Low-Med
Voltage Regulation	Quality control	Quality	Low
Power Factor Control	Quality control and loss reduction	Quality	Low
Phase Imbalance	Quality control and loss reduction	Quality	Low
Losses	Loss reduction	Energy	Med

Normal capacity, contingent or emergency capacity, and replacement are all primarily asset-based services. Deferred or avoided investment in capacity is generally considered to be the dominant potential benefit that DG services offer. Asset management is improved because of direct tangible financing savings due to deferral along with the less tangible but valuable ability to observe load growth patterns in an area longer, before committing major resources and thereby reducing extra costs imparted by uncertainty. Equipment replacement provides the same forms of investment deferral benefits, but the magnitudes are smaller, as reflected in the smaller equipment replacement budgets for most distribution utilities.[104] Extended life may also reduce expenses associated with maintenance and repair.

Voltage support and regulation, power factor control, and phase imbalance are primarily quality control services, and they exhibit complex interactions with each other. Improving power factor can also improve voltage levels, but can result in over-correction. Likewise, losses are affected by both power factor and line imbalance. The scale of these services that can be provided by DG is usually (but not always) low relative to capacity assets such as feeders, transformer banks, and associated substation equipment, as the investments required to correct quality problems are much smaller. New substations and associated feeders typically cost in the range of hundreds of thousands to millions of dollars, whereas equipment for voltage and power factor control typically ranges between tens and hundreds of thousands of dollars. Capacity needs also may be impacted, though. For example, an area with very poor power factor decreases the real-power carrying capacity and therefore requires more capacity to deliver a given level of useful energy.

Reducing losses affects costs by reducing the gross energy generated, ultimately reducing customer bills if these costs are passed onto customers. Fewer energy purchases needed to provide a given level of end-use energy increases the efficiency and asset utilization of the distribution system.

Recommendations

The key features for each distribution service category drive the recommended approach for unbundled pricing. The recommended pricing mechanism and key contract terms are summarized in Table 34 below. The features and drawbacks of the recommendations are discussed and contrasted with alternate methods. The key factors discussed include uniformity, scale, transaction costs, response time, partial subscription, verification, precedents, and implementation. These recommendations apply in the most prevalent situations, but because distribution technical, financial and regulatory/rate issues can vary significantly throughout California, there may be situations in which the best practice differs from the recommended approaches described below.

Bilateral contracts are not recommended as general practice for any of the three service categories. A one-on-one agreement for DG-provided distribution services may be appropriate in unusual situations, such as where there is only a single provider capable of delivery in adequate time (e.g. an existing generator). The prudency of bilateral agreements proves very difficult to defend, unless there is a tangible and demonstrable benefit to customers as a whole.

Table 34. Recommended Pricing Summary

Category	Distribution Services	Best Pricing Mechanism	Key Contract Terms
Asset	Normal Capacity Contingent Capacity Replacement	RFP / Auction	Contract duration, dispatch details (notice, number of hours, number of days, which seasons)
Quality	Voltage Support Voltage Regulation Power Factor Phase Imbalance	Price Posting	Required location, performance and monitoring Time period definitions and requirements
Energy	Losses	Price Posting	Time-varying value of loss reduction

Asset-Based Services

Services that defer or offset asset investments are best priced using an RFP or auction mechanism. This recommendation is driven primarily by large and lumpy nature of most distribution asset investments, longer response time, deleterious impacts of partial participation, and few precedents for pricing. Transaction costs are small relative to the potential savings, and can be reduced for the smaller increments fairly easily.

Not all areas have impending investments, making a uniform homogenous service price particularly difficult. Even for those areas where investments are imminent, the marginal capacity costs vary substantially between planning areas.[105] These services address what are generally large lumpy investments. Large increments with long lead times favor a full

RFP-proposal-selection process to obtain the most competitively priced agreement. The scale justifies the larger transaction costs. Transaction costs need not be tremendously high for auction-style procurement for smaller increments. For routine auctions, general terms can be stipulated up front as qualification to participate in price bidding,[106] and then decisions on particular projects can be posted with a minimum quantity to ensure sufficient participation and a maximum quantity to limit over-subscription. This method avoids excessive administrative costs associated with long request-proposal-negotiation cycles when smaller investment increments are being considered. For larger increments, stipulating general terms as prerequisite for submitting price bids can also shorten cycle time.

A critical distinction between asset services and the others is the effect of an incomplete or partial response. For example, if a substation upgrade is planned because of an anticipated 1 MW of capacity shortfall, DG capacity of 200 kW would likely not alter the investment plan. If the participation level is not enough to defer the investment, then no real savings are realized. Price posting may lead to an actual increase in costs if there is insufficient participation, in which case there would be no actual deferral and utility is paying twice for the same service. Likewise, too much participation leads to excessive costs, which can be controlled using a maximum quantity stipulation in the RFP (or in a posted tariff).

Delivered units are generally in capacity (kW of kVA). These are readily measured and verifiable. The impact on the system can be relatively easily calculated using standard load-flow models. This feature makes settlement terms fairly straightforward for any type of pricing mechanism, including posted tariffs.[107]

Quality-Based Services

Services that provide power quality control functions are best priced using a posted tariff mechanism. This recommendation is driven primarily by relatively small and dispersed nature of expenditures (both capital and expense) for quality control, short response time, relatively minor impact of partial participation, and existing tariffs for some components. The complex interactions of voltage regulation and control, power factor correction, and load imbalance, along with the potential for overcompensation and control difficulties render auction methods difficult to execute. The initial costs of establishing tariffs are amortized over time, making them small relative to the potential savings. It may be wise to initially post the most expensive to serve areas only (at least at first) to prevent cream skimming.

Most areas have power quality requirements that dictate capital and expense spending. The needs are not very uniform, though, and some areas may be well within specifications (therefore have nearly zero value for additional services). The services are required in relatively small increments, and dependent on local feeder load and other technical conditions. This variation suggests area- and time-varying rates. These tariffs could be simple location and time of use, contingent on load conditions, or even posted in real time or hour or day-ahead formats. The small size leads to higher relative transaction costs if priced through RFP/auction methods. Response times for power quality services are relatively short, and with existing equipment can be almost real-time.

A partial response can still reduce costs because additional corrections can be made with smaller expenses (smaller capacitors, etc.). Over subscription can lead to serious control problems, such as too high a voltage or excessively leading power factor, but this problem can be controlled using a maximum quantity stipulation in the tariff.

Some of the power quality units are measurable and verifiable (e.g. leading/lagging vars, current injection, etc.), although if impact on the system itself usually must be inferred from a circuit model. In some cases this is straightforward and in others quite difficult. The complex interactions make RFPs difficult to specify and proposals difficult to prepare and to evaluate. There is precedent for using tariffs: there are existing tariffs which charge customers for causing power quality problem (e.g. power factor charges, excess demand charges, voltage sag credits, etc.), and by symmetry set the price for reducing them, at least on the margin.

Energy-Based Services

Services that reduce gross energy purchases are best priced using a posted tariff mechanism. This recommendation is driven primarily by the granular and dispersed nature of expenditures for losses, very short response time, negligible impact of partial participation, and established existing tariffs in most retail and wholesale rates. The initial costs of establishing tariffs are amortized over time, making them small relative to the potential savings. Much of the reasoning is similar to the quality-based services discussion.

All areas have losses. The needs are not uniform, but fairly easily modeled. Loss reduction has the most value the further along a radial network one goes. Losses can be reduced in essentially continuous fashion (very small increments), and like quality problems are dependent all upstream conditions and local feeder load and other technical conditions.

These tariffs could be based on location and time of use, contingent on load conditions, or even posted in real time or hour or day-ahead formats. The small size leads to higher relative transaction costs if priced through RFP/auction methods. Response times for energy services are very short, and with existing equipment can be almost real-time.

A partial response still reduces costs because the service is directly displacing a variable expense. Units are measurable and verifiable [kWh], although the impact on the system itself usually must be inferred from a circuit model. Estimation of this impact is straightforward.

Most existing tariffs charge customers for losses as a pass-through cost, and by symmetry they set the price for reducing losses, at least on the margin. These costs are well known and documented. These only usually apply system average losses, though. Even if the losses reduced directly by a DG operator are reflected in a bill reduction, there is still an indirect savings for which the loss reduction is not credited: reduced losses for all of the other customer on the line due to the quadratic nature of distribution system losses with total power flow.

Table 35. Key Factors Influencing Best Pricing Mechanism Recommendations.

	Asset	Quality	Energy
Uniformity	Not needed everywhere. Some areas have zero cost.	Useful in most areas. Needs vary significantly. More important "downstream".	All areas have losses. Needs vary. More important "downstream".
Scale	Large lumpy increments	Small dispersed investments and expenses.	Granular dispersed expenses.
Transactions Costs	High for full RFP cycle, lower for price-only auction with prearranged terms.	Scale favors low per-transaction cost and reduces effect of fixed initial set-up costs.	Scale favors low per-transaction cost and reduces effect of fixed initial set-up costs.
Response Time	Long	Short	Very Short
Over/under participation	Either could increase costs.	Under still saves $. Over yields control problems.	Under still saves $. Over requires large counter-flow.
Verification: units, measures	KW easily verified	Voltage "in spec" is an end result. kvar lead/lag, phase power are direct inputs	KWh direct measure with indirect effect
Precedents	Few	Some elements included in some tariffs.	Average losses included in most tariffs.
Implementation		Complex interactions. Over-correction and control issues add difficulties.	Reduced losses may be included in bill. Reduced losses to others/system are not.

Application of Service Definitions and Pricing Concepts to DSM

DSM measures refer to a broad category of devices and designs that reduce the power demands on the utility grid through reductions in usage at the customer end use. DSM includes efficiency measures such as compact fluorescent lighting and variable speed motors; design measures such as building orientation, day lighting and insulation; usage shaping measures such as thermal energy storage; fuel substitution such as gas absorption cooling; and active response measures such as curtailable load programs. DSM measures provide services without the complications arising from interconnection, safety, or environmental issues that arise with DG.

DSM programs can provide a majority of the benefits discussed above for DG devices. Specifically, DSM can provide the following:

Asset Based Services

- Normal Capacity. Reduced demand reduces the need for additional capacity in the same fundamental manner as local generation by reducing the net capacity requirements, except that it subtracts from the demand side of the equation instead of adding to the supply side. The nature of the services is essentially the same as for DG described earlier.
- Contingency Capacity. DSM offers the advantage of not "tripping off line." Certain types of active or dispatchable DSM can prove especially valuable if automated control is available to the utility. Even without automated control, programs such as curtailable load could allow a utility to reduce the loads on equipment running at emergency ratings and bring the equipment into normal operating ranges.
- Equipment Life Extension. As for normal capacity, DSM can provide the same equipment life extension benefits as DG

Quality Based Services

- Voltage Support and Regulation. DSM can provide some small benefits, but those benefits would likely overlap with both capacity and losses reduction benefits. DSM cannot provide power injection or regulation support.
- Power Factor Control. DSM would not generally provide benefits in this area, but may be able to contribute when the load reduction is mostly inductive, such as a large motor or electric welder.
- Phase Imbalance. DSM can improve phase balance when the reduction is a single-phase demand connected the most heavily loaded phase. DSM can sometimes serve this purpose more adequately than by rewiring single-phase connections when the phase imbalance is time varying.

Energy Based Services

- Losses Reduction. System losses are reduced in the same way as with DG.

Technical Factors Influencing DSM Service Pricing Strategies

Short vs. Long Term Service Benefits

The broad nature of DSM programs makes it impossible to make a single blanket statement regarding short and long-term benefits. Some measures such as fenestration or building orientation would easily last 30 to 50 years. Others such as curtailable load and direct-load control measures can be signed to specific contract lengths that match the length of the benefits they are providing. For example, to achieve a three-year deferral of a major capacity addition in an area, a utility might use three-year contracts for curtailable load as part of their deferral strategy.

Measurement and Verification

Some DSM measures have significant uncertainty about their longevity because they can quickly be replaced with a less efficient end-use. The classic example are compact fluorescent lights that may only stay in place for a short time, until the owner decides to replace the light bulb with a standard incandescent (or the bulb moves out of town with the owner or tenant). The issue of persistence is particularly a concern in lighting programs, but also applies to building energy management systems, thermal energy storage systems that are discarded, and other potentially short-term energy reduction approaches. At a system level, the persistence problem can be addressed through an assumed reduction in benefits over time. The diversity at the system level obviates the need for any detailed analysis of specific customer actions. At the distribution level, however, the actions of a few large DSM participants may have a significant impact on the ability of the utility to realize any local benefits. Because the success of a DSM program depends upon both the effort of the DSM marketer, and the willingness of the actual end-use customer, substantial care should be taken in the development of the contract terms to link payment to DSM performance. The performance should also be adjusted for measure persistence, and statistically determined "reliable" load reduction levels. DSM programs would therefore require a careful verification process to assure that the DSM participant is supplying the assumed benefits.

The difficulty of monitoring and evaluation of many, individually small energy efficiency measures for a targeted asset-deferral benefit makes more active measures such as curtailable, or interruptible credits a more feasible alternative. However, energy service companies (ESCOs) may be able to provide self-monitoring of their aggregate load reductions and therefore enter into contracts with larger amounts of load reduction. In addition, other distribution level benefits such as losses reduction that apply system wide can be effectively targeted with increased efficiency. In these cases, less monitoring is required on individual installations of measures since there is not a minimum amount of load reduction in a specific area that must be achieved to maintain a reliable system.

Lead Time

Beyond the problems of measurement and verification, poor persistence, and the aggregation of many small load reduction measures, lead-time can also be a stumbling block in capturing distribution system benefits. Typically, utility lead-time for installation of a new substation is on the order of two years, while the installation of a typical feeder is on the order to one year. Because of the time required to market, and then install efficiency programs in sufficient numbers to achieve adequate penetration levels to defer investments, these time frames are often too short to use efficiency as a targeted approach.

In cases where longer lead times are available, this problem is not as severe. In the 1992 PG&E Delta Project, significant targeted load reduction measures were successfully put in place to defer expensive capital projects until a low cost engineering solution was identified.[108]

Operating Information – Efficiency Programs

Unlike DG devices whose output can be directly measured and metered, the load reductions associated with DSM options must typically be developed from statistical analyses. This analysis is necessary because the large number and small size of the typical energy efficiency measure does not make end-use specific metering practical.

In addition, the statistical analysis is needed to determine the amount of actual load and energy savings provided by the DSM measure. Unlike a DG device whose output can be determined from engineering specifications, the benefit attributable to DSM is dependent upon numerous factors that are independent of a particular DSM measure. Most of the uncertainty surrounding attainable load reductions is the result of differences in individual customer behavior. Some examples of factors that can affect realized load reductions are shown in Table 36 below.

Table 36. Factors Influencing Realized Load Reductions

Factor	Impact
Desired Lighting Quality	Lower lumens or light quality from a compact fluorescent bulb may result in the owner turning on more light fixtures than were previously used.
Comfort Level	More efficient device may lower a customer's bill, but the lower bill may encourage the customer to set the thermostat to a more comfortable setting, thus re-consuming some of the expected energy savings.
Output Levels	An industrial customer's energy usage may vary with plant production levels. Changes due to plant production would have to be separated from energy savings due to DSM measures.
Weather effects	Moderate weather may result in greater than expected energy savings. Similarly, extreme weather could reduce expected savings. For example, a heat pump might require substantial electric resistance heating back-up in extreme conditions.
Balance of System	Benefits of any specific DSM measure often are a dependant on decisions made regarding other aspects of a user's facility. For example, insulation, fenestration and HVAC all affect cooling loads. A more efficient HVAC system reduces the incremental benefit of higher insulation, or improved window placement.

Operating Information – Active Control Programs

Active control programs do not have these same operational limitations as the efficiency measures discussed. The services that derive from load curtailment provide more value for the utility when the distribution system operator has direct control of the loads as opposed to voluntary participation.

In addition, the contract terms can specify non-compliance penalties, number of hours of operation, and many other terms that are almost exactly parallel to a contract with a distributed generator for dispatch during peak conditions. In fact, in response to curtailable load credits, customers commonly resort to operating their own standby generation when asked to curtail rather than reduce energy consumption. Either approach achieves similar load reduction impacts on the utility system.

Pricing Distribution Services Provided by DSM

As discussed above, DSM can offer a subset of the DG services to the distribution company. For those services that DSM can provide, the differences between the load injection of a DG and the load reduction of a DSM measure are immaterial. What does matter, however, is the determination of the amount of load reduction that DSM can be reliably expected to provide, and the coincidence of that load reduction with the likely period of need.

For example, a summer fruit packing plant may be able to provide substantial curtailable load to the utility in the summer, but that contract would be valueless to the utility if there is a winter contingency problem in the area (when the packing plant is shut down). Similarly, a contract for long-term sustained load reduction would be a poor utility investment if the customers can quickly revert to their prior energy usage levels.

Pricing Mechanisms

Another issue for DSM is the magnitude of the individual load changes. It is conceivable that hundreds of DSM measures might be required to equal the load change of one DG device. This fact will limit the feasible contracting options for DSM measures, as compared to DG.

The DG section discusses three pricing mechanisms: 1) Price Posting; 2) RFP/Auction; and 3) Bilateral negotiations. Price posting is similar to the way utility DSM programs have been evaluated in the past. In most of those cases, however, the emphasis has been on generation energy and capacity savings, which are constant over a utility service territory. Focusing on distribution benefits creates problems with mismatches between posted and actual benefits, both with respect to location of the benefit and duration of the benefit. The posting method also does not present a mechanism to assure that sufficient load change is attained to allow realization of the expected distribution benefits.

The RFP/Auction mechanism can be applied to DSM measures in either of two conditions are met: 1) the DSM measures are individually large enough to justify the administrative cost of the RFP/Auction (e.g.: curtailable commercial or industrial customer), or 2) the DSM measures are proposed as a package by an ESCO or similar aggregator entity. This aggregation approach where an ESCO can aggregate a combination of efficiency measures, curtailable load, and on-site generation to respond to an RFP is probably the most practical approach to using efficiency programs in a targeted distribution level load reduction.

The last pricing mechanism, Bilateral Contracting, potentially offers a good fit to some DSM programs. While the transaction costs are high, the targeting of utility efforts to a select subset of customers is consistent with the opportunities available to DSM. DSM provides benefits by reducing specific end-use consumption --- so the potential for DSM depends upon the saturation of those end uses within the target population. Direct negotiation with larger customers or customer aggregator representatives may be the most efficient method for targeting usage in an area and setting distribution payment levels. Bilateral contracts theoretically risk higher costs to the utility because of a lack of bidding competition. The limitation of DSM opportunities to pre-existing customer end-uses, however, would preclude market competition in many cases.

Recommendations

In summary, DSM can provide a subset of the services of DG. Active control approaches such as curtailable load provide the most suitable needs for targeted asset-based distribution benefits, although aggregated efficiency measures, most likely by third parties, are feasible with sufficient lead-time, and performance monitoring. Energy efficiency measures are more readily adaptable to provide energy-based distribution services such as losses, as well as system benefits commonly attributed to these programs in current practice. Unfortunately, most DSM measures cannot effectively provide quality-based distribution services.

The small energy savings of many DSM measures, and the associated transaction costs makes posted prices the only practical option for many efficiency measures. Posted tariffs, however, can lead to over-payment in areas where there are no or few distribution benefits for load reduction. For larger customers, or customer aggregators, the impacts may be large enough to warrant a RFP/Auction or bilateral contracting in targeted areas.

In any DSM contract, extra care must be taken to assure that the estimated services are provided by the DSM measures. The monitoring should address initial customer participation levels, measure persistence, and net usage changes attributable to the DSM measures (as opposed to outside factors).

Conclusions

Several distribution services have been identified that can in many instances be provided by distributed resources. The specific services and DR technical capabilities are summarized in Table 37. The technical factors that influence the capability to provide these services in some cases depend on whether the distributed resource is local supply (distributed generation at a customer site or an independent DG IPP) or local demand (DSM), but in other cases is independent of this distinction.

__Table 37. Distribution Services Provided by DR__

Service	Net Load (Customer Generator)	DG IPP	Net Load (Customer DSM)
Normal Capacity	Yes, changes in net load can defer capacity investments.		
Contingency Capacity	Yes		Yes, with additional benefit of not "tripping off line".
Replacement	Yes		
Losses	Yes – reduction in load results in fewer losses to a customer generator, and may reduce other losses on UDC system	Generation can reduce losses on UDC system	Yes- same benefit as customer generator
Voltage Support	Yes- Changes in net load can provide voltage support		
Voltage Regulation	Yes- Generators can provide voltage regulation		No
Power Factor	Yes		Yes, with inductive loads.
Phase Imbalance	Yes		Yes, with single-phase loads.

Distribution services fall into three fundamental categories:

(1) *Asset-Based*: those that primarily substitute or defer investment in major capital assets (such as capacity).
(2) *Quality-Based*: those that provide a power quality control function (such as voltage support).
(3) *Energy-Based*: those that substitute for energy purchases (such as losses).

Deferred or avoided investment in capacity (asset-based) is generally considered to be the dominant potential benefit that DG services can offer[109]. For any particular UDC, the actual potential for DR to offset such investments is highly situation-dependent, reflecting both time and location-specific costs and benefits.

Procuring distribution services provided by DG and DSM requires specification of more than just a price. It requires clear definitions of the contract structure, the contract terms, and the mechanism by which the price and quantity levels are determined. The three key pricing mechanisms evaluated in this report are bilateral agreements, RFP/auction competitive procurements, and posted tariffs. The recommended approaches are derived by matching the attributes of the service categories to the features of the different pricing mechanisms. Developing an appropriate pricing mechanism for each service requires consideration of several key issues and drivers.

(1) Attributes of the product or service being provided.
(2) Characteristics of the market for those services.
(3) The incentives that exist for the utility and providers.
(4) Risks faced by the various potential participants.
(5) Practical implementation concerns.

The recommended pricing strategies for each type of service (asset, quality and energy services) are illustrated in Table 38 and summarized below.

- Bilateral agreements should rarely be used for the distribution services identified in this report because they are likely to result in an inefficient price and can limit innovation and potential cost savings. Bilateral agreements may be appropriate for some DSM applications to overcome the saturation and persistence issues with energy efficiency measures.
- The scale of most large asset-based distribution requirements favors the RFP/auction approach where there is sufficient lead time and DR benefit to accommodate the timing and administrative costs of a competitive pricing mechanism.
- The smaller scale of DR benefits and shorter response time needed for quality and energy based services favors a posted tariff approach.

Asset and energy services are more easily unbundled than quality-based services. Although reactive power and line imbalance power are easily measured, they exhibit complex interactions with the end effects on power factor, line voltage, and losses that make terms and pricing particularly difficult.

Table 38. Recommended Pricing Strategies

Pricing Strategy	Asset	Quality	Energy
Bilateral	Some DSM		
RFP/Auction	•		
Posted Tariff		•	•

Poorly designed pricing mechanisms and contracting forms can eliminate otherwise cost effective opportunities for DR to participate in providing these services. Adopting appropriate pricing approaches for distribution services has the potential to lower UDC costs of service and provide DR owners/operators the opportunity to share in the benefits they can provide to the distribution system.

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Appendix: Major Distribution System Components

Substation transformer

A voltage transformation device that steps the transmission voltage down to distribution level voltages. Substation transformers typically range in size from 5 to 40 MVA. An example substation transformer has a 115 kV primary connected to the transmission, and a 12 kV secondary feeding the distribution system.

Substation bus

A substation bus is a configuration of uninsulated conducting bars or tubes that are used to connect the substation transformer's primary and secondary terminals to lines, sectionalizing equipment and feeders.

Substation protection

Substation protection is a general term describing the use of equipment to protect the distribution and transmission system alike from electrical fault conditions observed at the substation. The protection equipment includes circuit breakers, fuses, and surge or lightning arrestors.

Feeders

The term feeder refers to the primary distribution lines that connect the distribution substation to load centers.

Facility support infrastructure

The facility support infrastructure includes utility poles, mounting hardware, guy wiring, foundations, pads and other mechanical structures that are used to construct a distribution system.

Laterals

Laterals refer to circuit lines that branch off the main feeders to serve individual pockets of loads. For example, lines feeding the side streets off of a main residential avenue are typically laterals.

Conductors and cables

Conductors and cables are the conducting wires used in transmission and distribution systems alike. Conductors are uninsulated, and are therefore used only in overhead systems. Cables are insulated conductors, used in underground systems, certain overhead systems with high exposure to tree branches, and secondary connections to customer facilities.

Capacitors

Capacitors are energy storage devices used to supply capacitive reactive power to the distribution system and offset the inductive reactive power demand from lines, transformers, and inductive loads.

Voltage regulators

Voltage regulators are variable transformers used to regulate the voltage at substations and along feeder lines. They are most commonly used to boost the voltage in areas where an excessive voltage drop has occurred between the substation and area load.

Sectionalizing equipment

Sectionalizing equipment refers generally to any circuit device capable of disconnecting sections of a distribution line. These include fuses, circuit breakers, reclosers, automatic and manually operated switches, etc. A sectionalizer refers specifically to an automatic switching device that is designed to operate after sensing a predetermined number and magnitude of current surges.

Circuit Breakers

Circuit breakers are circuit interrupting devices capable of breaking short circuit or fault currents, and which can be automatically opened and closed. They usually operate in conjunction with a relay to break the circuit upon detection of fault level currents.

Reclosers

Reclosers are circuit breakers that are designed to automatically reclose following a circuit breaking operation. The purpose is to allow temporary faults, such as that caused by a falling tree branch, to clear, and then quickly re-establish service to the load area. They are typically programmed for a combination of sequential time delays, and finally remain open if the fault fails to clear.

Fuses

Fuses are current limiting devices that heat up and sever circuit connections given a predetermined curve of over-current magnitude and duration. Unlike breakers and reclosers, individual fuses fail upon operation, and cannot re-establish the circuit connection. They are typically used on laterals to prevent faults occurring along the lateral from affecting the primary feeder. They are also used in network systems to protect the primary feeders from faults in the secondary or spot network.

Network protectors

A network protector is a circuit breaker with integrated control equipment used to connect and disconnect a secondary network with a primary supply feeder. The control relays are programmed to disconnect the network upon detection of current flowing backward out of the network into the primary, and reconnect the network when conditions for proper power flow are detected.

Secondary transformers

Secondary transformers in radial systems convert the primary distribution voltage to customer service voltages, typically 120V, 240V, and 480V. In networks they link primary feeders to secondary or spot network

Engineering and Institutional Limitations of DG as a Means to Provide Transmission and Distribution (T&D) Services

Summary

Overview

This memorandum identifies the technical and institutional constraints of distributed generation (DG) in general, and for specific DG technologies, that may limit or prohibit the DG technologies' ability to provide the transmission and distribution (T&D) services identified in Task 2.1 (*Transmission System Services Provided by Distribution Level Distributed Generation*) and Task 2.2 (*Benefits and Pricing Strategies for Services Provided by DG and DSM to the Distribution System*). [110]

DG's ability to provide such services is hampered by technical limitations, business practices, and regulatory and legal constraints. "Technical limitations" refer to the ability of various DG technologies to satisfactorily fulfill the engineering requirements for each T&D service. Business practices and regulatory and legal constraints are institutional in nature. Technical innovation, learning and improved procedures by utilities, and ongoing regulatory evolution are improving DG's opportunities to overcome such barriers.

There are three fundamental ways that these limitations impact effective participation by DG in providing T&D services. The proposed service may be:

- Infeasible- DG is technically incapable of providing the service;
- Unprofitable - it is too costly for DG to comply with technical or institutional constraints; or
- Prohibited- it is contractually or legally restricted for DG to provide the services.

The remaining sections of this memorandum are organized as follows:

Section 2 - A brief review of the T&D services identified in Tasks 2.1 and 2.2.
Section 3 - Technical limitations: DG capabilities and service requirements.
Section 4 - Limitations due to DG's Impact on Distribution System Facilities and Operations.
Section 5 - Institutional limitations: business practices and regulatory rules.
Section 6 - Conclusion.

In addition, there is a short appendix addressing interconnection related barriers. DG interconnection has been dealt with in detail by California Energy Commission staff, stakeholders and the California Public Utilities Commission over the last year.[111] This appendix is intended to only give a brief review of interconnection related technical and institutional barriers.

DG T&D Services Review

DG has the technical potential to provide services to both the transmission system and distribution system. *Transmission* services, characterized in Task 2.1, include both localized capacity benefits for area-specific networks and bulk transmission system services. Potential DG-provided *distribution* services were characterized in Task 2.2, and can grouped into services that (1) defer or offset *asset* investments, (2) provide power *quality* control functions, and (3) reduce gross *energy* purchases. Many localized transmission services have close analogies in distribution services. Furthermore, several services overlap significantly with others due to technical reasons, such as voltage support, loss reduction, and power factor control. The general categories into which the potential DG-provided services fall are summarized in Table 39.

Table 39. DG T&D Service Categories

	Transmission	**Distribution**		
Service		**Asset**	**Quality**	**Energy**
Normal Capacity	•	•		
Contingency Capacity	•	•		
Equipment Life Extension	•	•		
Voltage Support	•		•	
Voltage Regulation			•	
Power Factor Control			•	
Power Flow Balance	•			
Phase Imbalance			•	
Loss Reduction	•			•
AGC/Regulation (A/S)	•			
Spinning Reserve (A/S)	•			
Non-spinning reserve (A/S)	•			
Replacement reserve (A/S)	•			
Reactive Power / Voltage Support (A/S)	•			
Black Start (A/S)	•			

These services are defined briefly for reference in Table 40. Details are provided in the associated task reports.

Table 40. DG T&D Service Definitions

Service	T/D	Definition
Normal Capacity	T&D	The prevention of excessive currents and overloads during peak loading periods given normal conditions (all major components in service).
Contingency Capacity	T&D	The prevention of excessive currents and overloads during peak loading periods given emergency or contingency conditions (one or more major components out of service).
Equipment Life Extension	T&D	The deferral of facility replacement projects that may be justifiable if DG reduces loading on older equipment to levels below an appropriate de-rated value.
Voltage Support	T&D	The prevention of excessive voltage drop during peak load periods, both under normal and contingency conditions.
Voltage Regulation	D	Controlling periodic swings of the voltage on a particular part of the system caused by larger fluctuating loads.
Power Factor Control	D	Injection of reactive power into the distribution system to balance the reactive power demand from inductive loads, motor loads, and the inherent inductance in the power delivery components.
Power Flow Balance	T	The ability to alter the flow patterns on a multi-path system experiencing congestion problems.
Phase Imbalance	D	Correction of unequal distribution of single phase loads on the three-phase system
Loss Reduction	T&D	The reduction of currents and losses on conductors and transformers that results when DG provides an alternate, local supply for area loads.
AGC/Regulation (A/S)	T	The generator provides system regulation service by adjusting output and voltage as necessary to maintain stability.
Spinning Reserve (A/S)	T	The generator provides a quantity of unloaded capacity synchronized to the grid that will ramp up within 10 minutes.
Non-spinning reserve (A/S)	T	The generator provides a quantity of capacity that is not synchronized to the grid but can ramp up within 10 minutes.
Replacement reserve (A/S)	T	The generator provides a quantity of capacity that will ramp up within 60 minutes.
Reactive Power / Voltage Support (A/S)	T	Generators maintain localized voltage within ISO tariff specified power factor range.
Black Start (A/S)	T	Generators supply power to de-energized portions of the grid as part of an orderly power restoration process.

Technical Limitations

Each T&D service described above depends dominantly on a few key engineering requirements. In turn each particular DG technology exhibits its own capabilities with respect to these requirements, and thereby its ability to provide the various T&D services.

Technical Requirements

Each T&D service requires particular characteristics of a DG unit in order to physically meet the needs of the grid. The core characteristics are as follows.

1. *Dispatchability*. Can the unit be turned on and off when needed at the discretion of the grid operator? Most services must be provided in response to grid conditions and thereby need a dispatchable resource. In some cases dispatchability is helpful (e.g. more valuable) but not necessary. For example, Normal Capacity can be provided by a solar electric system where capacity needs are high during daylight hours (fairly predictable). However, Emergency Capacity is much less predictable as to when it will be needed, and dispatch is needed to respond to sudden emergencies.

2. *Availability*. Is the unit working when it is expected to be? For example, a photovoltaic system is not dispatchable, but does have a high availability during daylight hours. By contrast, a diesel generator is dispatchable, but may only be available 90-95% of the time when needed, depending on the maintenance and repair characteristics. A unit must be available in order to be dispatched. Multiple units in a single installation increase the aggregate availability of DG units relative to larger single units. However, some intermittent renewables have common mode unavailability (e.g. no wind or a very cloudy day) that lowers their ability to provide some services.

3. *Start-up time*. How fast can the unit start providing service? Some services need to initiate quickly (e.g. unforeseen sudden contingencies), where others do not (e.g. loss reduction).

4. *Response time*. How quickly can the unit change service level? Some services need to react quickly (e.g. voltage regulation), others do not (e.g. normal capacity).

5. *Reactive Power*. Can the unit provide leading and/or lagging VARs? This capability is needed for power factor control and can be helpful for voltage support and regulation.

6. *Islanding*. Can the unit operate independently of the grid? Islanding capability is needed for black-start operation, or when the DG unit is also used for customer back-up power.

7. *Coordinated Control*. Does the unit need to be coordinated closely with other sources or can it be locally controlled effectively? Coordinated control becomes important for those services that exhibit complex interactions with each other, and also becomes an

important consideration at higher DG penetration levels where there are potential power quality and stability problems, such as harmonics and hysteresis problems.

Table 41 below summarizes which of these core service requirements is necessary for each of the T&D services.

Table 41. DG T&D Service Requirements

Service	Dispatchability	Availability	Start-up Time	Response Time	Reactive Power	Islanding	Coordinated Control	Comment
Normal Capacity	H	N	Ø	Ø	Ø	Ø	Ø	
Contingency Capacity	N	N	Ø	Ø	Ø	Ø	Ø	
Equipment Life Extension	H	H	Ø	Ø	Ø	Ø	Ø	
Voltage Support	N	H	Ø	N	H	Ø	N	
Voltage Regulation	N	H	Ø	N	H	Ø	N	
Power Factor Control	Ø	Ø	Ø	Ø	N	Ø	N	
Power Flow Balance	H	N	Ø	Ø	Ø	Ø	Ø	
Phase Imbalance	H	N	Ø	Ø	Ø	Ø	Ø	Single Phase
Loss Reduction	H	N	Ø	Ø	Ø	Ø	Ø	
AGC/Regulation (A/S)	Ø	N	Ø	N	Ø	Ø	H	
Spinning Reserve (A/S)	Ø	N	Ø	Ø	Ø	Ø	H	
Non-spinning reserve (A/S)	N	N	N	Ø	Ø	Ø	Ø	
Replacement reserve (A/S)	N	N	Ø	Ø	Ø	Ø	Ø	
Reactive Power / Voltage Support (A/S)	Ø	Ø	Ø	N	N	Ø	N	
Black Start (A/S)	H	N	Ø	Ø	Ø	N	N	Scale is Importan t

N: Necessary, H: Helpful, Ø: not critical

Technical Capabilities

Technical capabilities of DG derive from the attributes of the core components of a distributed generator: the prime mover, the generator, and the control system. All three components need to be specified to fully characterize a DG unit. However, specific technical requirements that a DG installation must meet often depend only on the features of a single component.

Given sufficient penetration and control, distribution level DG can reasonably provide each of the reserve services (spinning, non-spinning and replacement) by quickly reducing the loading needs of area substations and by extension the bulk transmission. From the ISO perspective, the generation may be little more than a demand reduction device, but by definition it will be dependent on that reduction if the DG unit is to qualify as a reserve service provider. Relatively high adoption rates of particular types of DG can also conceivably provide reactive power and bulk system voltage support, by modifying the power factor of the substation loads.

The usefulness of distribution level DG for regulation and black start applications is minimal in the current context of grid operations. However, future scenarios with significantly higher levels of DG penetration do allow for DG to play a limited role. Large aggregations of DG under control of an ISO could conceivably be controlled to ramp or reduce flows to counter fluctuations on the bulk system. Providing black start services with DG may be the rare case. DG could provide them indirectly by creating small islands and therefore reducing the black start load requirements of system level generators.

Prime Mover

Table 41 summarizes the technical capabilities of the most common types of DG prime movers to meet four of the service requirements – dispatchability, availability, start-up time, and response time. Reactive Power, Islanding and Coordinated Control are primarily a function of generator type and control system, and are addressed in the next section.

Table 42. DG Prime Mover Capabilities

Technology	Dispatchability	Availability	Start-up Time	Response Time
Diesel	X	M	F	F*
Spark Ignition	X	M	F	M
Mini-turbine	X	H	M	F
Micro-turbine	X	H	M	F
Fuel Cell	X	H	M/S	B
Photovoltaics		H, D	F	C
Solar Thermal Electric		M, D	S	C
Wind		M, W	M	C

* Diesel is similar to spark ignition when operated in lean-combustion mode.
X: Fully capable; H: High, M: Medium, F: Fast, S: Slow
D: During daylight hours; W: Dependent on local wind resource
B: can be improved with batteries; C: non-dispatchable are generally resource-dependent and the response time is a function of the control system.

Dispatchability. The fuel-based technologies are dispatchable. Intermittent renewables are not.

Availability. Combustion turbines and fuel cells have a better-forced outage rate than reciprocating engines. Microturbines have the fewest moving parts of combustion-based technologies and longest reported mean time between failures. Photovoltaics have a good record of availability during daylight hours, less so with solar thermal electric systems as a result of moving parts. Wind generators have historically exhibited poor availability, although more recent installations show improved uptime and better wind resource prediction.

Start-up and Response Time. Reciprocating engines startup very quickly - usually less than ten seconds – provided that they are designed for emergency response and kept warm. Turbines take longer to reach their full speed, and recuperated turbines will operate at somewhat lower efficiency and capacity than their simple cycle level until they have warmed up, which may take 5-15 minutes. Turbines can adjust to loads very quickly due to their low inertia relative to reciprocating engines of similar capacity. Natural gas reciprocating engines and diesel engines operating in "lean-burn" mode (for lower NOx emissions than stoichiometric) do have some problems adjusting to loads that change significantly with short duty cycles. Fuel cell response time depends on whether it is at full operating temperature or not.[112] At full operating temperature, the response is little slower than internal combustion engines, although the response has been reported to be due to the reformer, not the fuel cell[113]. The response time for fuel cells and for all DC systems can be improved with the addition of a small amount of battery storage.

Generator/Controls

Many important DG characteristics are determined by the generator type (AC Synchronous, AC Inductive, or DC Inverter) and control system rather than the prime mover. Equipment for protecting the generator and maintaining adequate power quality is usually included in a generator package. This equipment protects the generator from conditions such as over/under current and voltage, and phase imbalance. These controllers also incorporate many of the functions required by utilities for interconnection, such as protection from fault current, failure to synchronize, reverse power, ground faults, and others. Some important connection considerations and capabilities specific to the three basic types of generator are summarized below in Table 42. AC induction generators are not capable of providing reactive power to the grid, nor can they operate without grid supply.

Several of the control systems capabilities and limitations are embedded in the generator type as seen above. Advanced communication and control technologies such as distributed automation, supervisory control and data acquisition (SCADA) systems, telemetry, and advanced metering improve measurement and verification and also enable direct control by the utility. This is more of a bonus feature than a technical requirement. There may be problems with the stability of the distribution system if there is no coordinated control of a large penetration of generators. Voltage oscillations could occur in situations where the controllers of the different generators counteract with each other or with utility voltage regulators. Control fluctuations are more sensitive if multiple generators are located far from a substation, where the high impedance can exacerbate the interaction of high frequency control changes. Each of the generator types can be controlled in a coordinated fashion, thus preventing some of these problems, but some of the advanced communication and control technologies will be required. The unwanted problems associated with large numbers of generators can be addressed using the centrally coordinated control approach or in some cases by strictly limiting control features that are not critical to a generator's own operation. The latter approach would in effect "dumb down" certain classes of generation controllers so that they would be less likely to interfere with the utility or other generator control regulators.

Table 43. Electrical Connection Considerations and Capabilities by Generator Type

	AC Synchronous	**AC Induction**	**DC with Inverter**
Power Quality	Minimal considerations, unless transformer configuration generates 3rd harmonic.	Power factor (PF) considerations, associated power quality impact of paralleled capacitor banks.	Harmonics generated by inverter should be limited (IEEE 519)[114] at point of connection.
Protection & Safety	Most stringent protection requirements, due to self-excitation, synchronization, and sustained fault current considerations.	Fewer protection issues in general; ferroresonance concerns when operated with filter components.	Protection relatively simple due to low fault currents and inherently fast control; additional measures often required to prevent DC injection and islanding.
Interconnection	Typically the most costly interconnection process due to protection issues; is not allowed at all on certain networks. Fairly consistent process however due to utility experience and familiarity.	Simpler interconnection process (no self-excitation), unless application of PF capacitors has negative impact on distribution system.	Inconsistent process due to lack of technology understanding. Interconnection costs for identical systems may be negligible to prohibitive depending on utility.
Reactive Power	YES	NO	YES
Islanding	YES	NO	YES

Limitations due to DG's Impact on Distribution System Facilities and Operations

Distribution System Equipment and Service Reliability

Utility equipment has been installed to deliver electricity to customers on a system that delivers electricity in one direction (from area substations downstream to the customers), without consideration of additional sources. The operation and reliability of this equipment can therefore be affected by the presence of DG. This section summarizes some of the more contentious issues and concerns regarding distribution system equipment and reliability.

Reclosers

Reclosers are circuit breakers designed to automatically reclose following a circuit breaking operation. The purpose is to allow temporary faults, such as that caused by a falling tree branch, to clear, and then quickly re-establish service to the load area. DG's impact on reclosers can be significant, especially for those that close within a 1-2 second range. Interconnection standards require very fast generator disconnection to prevent problems with reclosers. These standards are sufficient but with high penetrations of DG it will become increasingly likely that some DG will still be connected after an instantaneous reclose, potentially causing damage if the sources are out of phase with each other. Even a small DG system could arc and prevent a fault from clearing, thereby causing the recloser to lock open and interrupt customers. This is a rare event, but should be expected occasionally as the number of installed systems increase. The utility can minimize the risk of these events by extending the reclose times beyond 1-2 seconds.

Voltage Regulators

Voltage regulators are variable transformers used to regulate the voltage at substations and along feeder lines. They are most commonly used to support and control voltage at the far end of longer radial feeders. However, their controllers are typically designed for unidirectional power flow. If DG causes power to flow back through a regulator, it will attempt to regulate the utility side voltage and adjust to an extreme setting. A DG installation may compel the utility to move a regulator or replace it with one with bi-directional flow capabilities.

Network Protectors

A network protector is a circuit breaker with integrated control equipment used to connect and disconnect a secondary network with a primary supply feeder. The control relays are programmed to disconnect the network upon detection of current flowing backward out of the network into the primary supply feeder, and reconnect the network when conditions for proper power flow are detected. A DG unit located within a secondary network can therefore cause the network protector to inadvertently trip if its output exceeds the area load at any point in time. It can also cause reverse flow if a fault occurs on the primary feeder. Cities with large numbers of network protectors already in service will likely put serious restrictions on the number and type of DG systems that can be installed within the networks, rather than deal with the high cost of upgrading the protectors to better accommodate the generation.

Fuse and Relay Coordination

Fuses are current limiting devices that heat up and sever circuit connections given a defined level and duration of over-current. Fuse designs are coordinated with relays controlling breakers, reclosers and sectionalizing equipment to minimize customer outages during faults on the distribution system. The fuses and relay settings are designed according to available fault currents along feeders, and these fault currents will be altered by the installation of larger DG systems. If the fuse and relay coordination is not adjusted to account for the DG, there is an increased potential for nuisance interruptions and increased customer outages. It is likely that utilities will expect the DG owners incur any costs associated with revising the fuse and relay coordination.

Islanding

Islanding refers to distributed generation inadvertently supplying an isolated section of the local grid after a fault causes an upstream device to disconnect the utility supply. In most cases, the generator will detect the loss of utility, but in rare circumstances, the generation and isolated load may be balanced and the disconnection may not cause a sufficient disturbance of the voltage and frequency of the generator. Utilities want to prevent islanding because of the threat to 1) utility personnel who may assume the lines are de-energized, 2) customer loads that may be damaged by an unstable supply, and 3) equipment that may be damaged if the utility recloses on an unsynchronized island. While rare, the probability of an island occurring increases as the ratio of generator capacity to local load increases. Islanding has been addressed exhaustively in DG interconnection standards, and there are many proactive measures for preventing it.

Power Quality

The impact of DG on system power quality has been addressed with standard requirements such as IEEE 519[115], which specifies harmonic limits for voltage and current at the point of DG interconnection. Nevertheless, utilities have other power quality concerns, such as a DG's exacerbation of voltage sags and ferroresonance conditions. While DG is likely to improve sag conditions in many cases, the strict controls imposed on DG to prevent islanding may in fact cause degradation of service with respect to sags. If a system fault causes the voltage to drop low enough to trip off a DG unit located far down a feeder, the voltage there will drop even further from the lost capacity support.

DG systems fed from underground cable with dedicated transformers risk causing ferroresonance, a condition that results in large, high frequency voltage swings that can damage utility and customer equipment. This specific ferroresonance condition can occur if the DG system trips off in response to a fault, leaving the transformer unloaded but still tied to the system.

As in the case of other problematic phenomena, these instances will be rare but will increase in likelihood with higher penetrations of DG, and will prompt utilities and regulators to periodically revisit their rules for DG operation.

Testing, Inspections and O&M

Utilities expect increased duties and labor needs to oversee start-up tests of the DG systems, perform operation and maintenance on new equipment associated with DG installations, and perform periodic site inspections and relay testing as required by interconnecting agreements.

DG Technology Specific Concerns

Generator Types

Technology specific interconnecting issues and requirements have been well documented in the developing interconnecting standards, and there is growing consensus on their treatment. Some of the issues associated with each generator type are summarized here.

Synchronous Generators. Synchronous generators are capable of self-excitation and are generally viewed by utilities as being the most likely to influence islands and recloser operation. In some cases, such as in New York, they are prohibited altogether from operating on networks that use network protectors.

Induction Generators. Induction generators require the grid or capacitor banks for excitation. When the grid provides the reactive current for excitation, the generators can cause voltage dips at start-up. An installation designed to use capacitor banks may require automatic disconnection of those banks in the event of an over voltage condition to prevent islanding.

Inverters. Inverters may offer some advantages over rotating generators, such as lower fault currents and better disconnect capabilities. However, utilities have less understanding and operating experience with inverters, and therefore still have concerns with their interconnection. Specific fault currents vary among the numerous generating sources and inverter technologies, making it difficult to make generalizations on their circuit protection impact. Larger systems may require site testing to ensure that harmonic limits defined by IEEE 519[116] are met, because the impedance of the feeder at the point of common connection influences compliance.

Transformer Configuration

Each type of transformer used to interconnect a DG system to the utility grid has specific operational characteristics that can affect the normal operation of the grid. Utilities are developing rule-of-thumb screens for selecting transformer types to be used by DG based on the distribution system characteristics. The transformers are distinguished by the winding configurations that are used to transform the voltage, and these windings respond differently to phenomena such as harmonics, fault contribution and detection, and ferroresonance. Utility concerns over these issues should diminish as they gain greater experience with the screening and selecting process.

Penetration Thresholds

The evolving standards and guides for DG interconnection hint at a practical limit to which the utility can accommodate DG without making fundamental changes in distribution system design. The definition of this limit is a hotly debated topic among utility distribution and technology experts.

There are two key indicators that can be analyzed to determine when DG penetration has approached a level requiring systematic changes.

System Stability Impacted. The reliable operation of the system is affected if the feeder voltage drops too low as a result of DG capacity suddenly dropping from the system. The owner(s) may have intentionally or unintentionally turned off the generator, or a fault may have occurred causing the DG to disconnect. If the feeder loading is high, the voltage after a utility breaker recloses on certain segments of the feeder may not be sufficiently high to serve the load. Moreover, the inrush current into the distribution system to make up for the lost capacity may exceed the substation breaker settings and cause an outage to the whole feeder. Typical design levels allow a 5% or, more liberally, a 10% voltage drop. This will be one of the more limiting factors in how much DG can be served from a distribution system without incorporating special controls. The amount of voltage drop is highly dependent upon both the size of the aggregate generation and its location on the feeder. A static and dynamic load flow analysis of the system operating at peak with and without the generators is needed to determine the impact DG has on feeder voltage.

Substantial Protection Practice Changes Required. Penetration becomes a significant issue when substantial changes must be made to the utility protection system to accommodate the DG. There is generally a sizable margin in the settings of protection relays and fuse sizes. Adding DG that can feed into faults erodes this margin. Sometimes simple changes such as reprogramming relays can be made to increase the margins, but at other times the protection scheme must be revised. Line apparatus such as fuses and reclosers may have to be changed out, potentially at a significant cost. When the level of DG capacity rises to the point at which this margin is gone, the system reliability may deteriorate. If the DG is concentrated near the substation, more DG can be accommodated without change; if concentrated at the feeder extremities, less can be accommodated.

Impact on Distribution Planning

Procedures for planning T&D systems have been developed for poles, wires, transformers, switches, capacitors, and other conventional grid hardware. Tools and procedures are simply not in place at most utilities for effectively evaluating the engineering and economic merit of distributed resources as T&D components. Long established power flow models used in distribution planning are particularly inadequate to analyze the system with a large penetration of generation, and would therefore need to be replaced. This lack of planning tools affects both utilities and regulators alike, as regulators and interveners are equally disadvantaged when it comes to judging the prudency of distributions system investments.

Utilities will ultimately need to make systemic changes in their operations planning based on the fundamental shift of the distribution system from a unidirectional to a multi-directional flow system. Such a change will impact how planners develop methods and implement strategies for dynamic voltage regulation, bi-directional fault detection and protection, the prevention or controlled use of islanding, system stabilization, and overall power quality. Equipment that has been in use for decades may possibly become obsolete and would need replacing to meet the new planning objectives.

Reliability concerns will have a large impact on the pace of planning transitions, and will likely cause utilities to plan conservatively in the near term. For example, planners will tend to want redundant facilities in critical contingency areas regardless of the presence of DG that can provide that capacity, until they gain experience and trust with the use that generation.

Institutional Limitations

Most institutional limitations affecting DG T&D services, both business practices and regulatory rules, are generally applicable to all DG technologies. Some institutional limitations apply to all of the T&D services that have been discussed (see Table 40), while some apply only to a few. The core institutional limitations affecting DG T&D services are as follows.

- *Unfamiliarity*. The lack of experience with DG in T&D systems, and the attitudes toward DG technologies held by engineers, regulators, and the public, imparts additional barriers. People tend to be skeptical of a "new" technologies or applications. This skepticism often results in underestimation of capabilities or overestimation of costs. This unfamiliarity also leads to requiring detailed engineering studies in excess of what is adequate. Education and more experience working with DG applications are needed to lower this hurdle.

- *Maintenance*. Existing maintenance and equipment replacement procedures make it difficult to effectively deploy DG for equipment life extension. Utilities typically do not have access to or keep historical record of the data that would be needed to properly evaluate a DG's impact on equipment life. Utility guidelines for equipment maintenance/replacement describe the loss of life calculations merely for providing operating guides, not for accurately predicting the life of the component. Projects to replace older T&D equipment can be deferred if the application of DG helps reduce loading to some pre-determined derated value based on age or ambient conditions. Should utilities increasingly adopt condition-based replacement and monitoring equipment such as transformer oil temperature monitors, DG for equipment life extension could become more practical.

- *Contracting and Permitting Terms and Conditions*. Some of the terms stipulated in DG T&D service contracts can be impediments to DG provision of T&D services, such as liability, insurance, indemnification clauses, or limitations in operating characteristics. These limitations can affect any of the potential DG T&D services.

- *ISO Requirements*. ISO requirements place an additional burden on DG provision of transmission-level services. These requirements include telemetry, minimum size, metering, and market design. While recent developments to reduce these limitations increase DG access to A/S markets, the owner/developer of DG must understand that simple interconnection to the ISO controlled grid can impose technical and contractual obligations.

- *Many Rules*. There are multiple and confusing standards and requirements, sometimes conflicting with one another, governing the various aspects of DG ownership, installation, permitting, interconnection, and operation. These encompass engineering standards and codes, building codes, fire codes, air quality regulations, utility guidelines, OSHA requirements, application procedures, inspection procedures, and safety codes, to list a few. Standardization of the installation and operation process for DG units for both energy and T&D services could greatly relieve this constraint.

Conclusion

DG is capable of providing several T&D services, but the extent to which DG can be successfully deployed to effectively supply them are limited by (1) the technical capabilities of various DG technologies, (2) technical requirements imposed by the grid and grid operators, (3) business practices by T&D companies, and (4) regulatory rules and requirements. Institutional limitations can be relaxed through standardized procedures, uniform standards, and experience. Technical capabilities and requirements are likely to adapt over time through innovation on the part of both DG manufacturers and utility engineers as their experience increases the knowledge base and comfort level. However, some technical barriers resulting from key characteristics of the prime mover will prevent some DG technologies from providing certain T&D services.

The key capabilities and limitations presented in this report are summarized in Table 43 below. Those technologies that have no significant technical or institutional limitations are labeled as "YES". Those that are prevented from performing the service by a technical or institutional issue are labeled as "NO". Those for which either a technical or institutional issue limits the ability to provide service to some degree are indicated as "LIMITED".

Table 44. Service-Technology Capabilities Matrix

	Combustion				**Chemical**	**Intermittent Renewables**		
T&D Service	Diesel	Spark Ignition	Mini-turbine	Micro-turbine	Fuel Cell	Photovoltaics	Solar Thermal	Wind
Normal Capacity	YES	YES	YES	YES	YES	LIMITED by resource availability [4]		
Contingency Capacity	YES	YES	YES	YES	YES	NO	NO	NO
Equipment Life Extension	LIMITED by institutional inability to quantify the value							
Voltage Support [3]	LIMITED by response time							
Voltage Regulation [2]	LIMITED by real-time dynamic response				NO	NO	NO	NO
Power Factor Control [1]	YES	YES	YES	YES	YES	LIMITED by dispatchability		
Power Flow Balance	YES	YES	YES	YES	YES	LIMITED by dispatchability		
Phase Imbalance	LIMITED to single-phase output							
Loss Reduction	YES	YES	YES	YES	YES	YES	YES	YES
AGC/Regulation (A/S)	LIMITED by response time		YES	YES	NO	LIMITED by dispatchability		
Spinning Reserve (A/S)	YES	YES	LIMITED by start-up time			LIMITED by dispatchability		
Non-spinning reserve (A/S)	YES	YES	LIMITED by start-up time			NO	NO	NO
Replacement reserve (A/S)	YES	YES	YES	YES	YES	NO	NO	NO
Reactive Power / Voltage Support (A/S) [1]	LIMITED by response time and need for coordinated control					LIMITED by resource dispatchability		
Black Start (A/S)	LIMITED by penetration level and need for coordinated control					LIMITED by resource dispatchability		

YES - Technical and institutional issues pose no serious limitation.
LIMITED - Technical or institutional issues limit capability to some degree.
NO - Technical or institutional issues prevent providing service.

[1] Not AC Inductive
[2] Source must be configured that enables fast dynamic response.
[3] Voltage support by effective load reduction.
[4] Value depends on resource-load correlation.

Appendix: Overview of Interconnection Barriers

Many studies, work groups, and hearings have investigated the technical and institutional barriers associated with process of interconnecting DG to utility grids. This appendix provides a short overview of the types of technical interconnection issues that can impact DG.[117]

Below is a table of basic functional and equipment requirements in California based on generator/control technology. This table is intended to provide some idea of the items that should be included and the issues that must be addressed for DG connection to the T&D grid.

Table 45. California Connection Requirements[118]

Feature	**Generator Type**		
	3-phase Synchronous	Induction	Inverter
Interconnection disconnect device (manual, lockable, visible, accessible)	X	X	X(b)
Over-voltage trip (110% of nominal voltage)[(a)]	X	X	X
Under-voltage trip (88% of nominal voltage) [(a)]	X	X	X
Over/Under frequency trip (60.5 Hz / 59.3 Hz)[(a)]	X	X	X
Synchronizing check (A: Automatic, M: Manual)	A/M		

Notes:
X – Required feature
(a) – Adjustable settings may be required by utility for systems over 11 kVA.
(b) – Non-islanding inverters 1 kVA or less exempt.

Interconnection requirements are not yet standardized across the country. For example, the interconnection guidelines in Texas also include specifications for the following.

- Interrupting devices (capable of interrupting max available fault current)
- Generator disconnect device
- Ground over-voltage or over-current trip
- If exporting, power direction function may be used to block or delay under frequency trip
- Automatic voltage regulator
- Telemetry/transfer trip

Several fundamental barriers can restrict the ability to connect a DG unit to the grid at all, without which the question of providing T&D services is moot. Numerous such interconnection barriers have been identified and discussed in some detail in a recent study of 65 DG projects (0.3 to 56 MW, of which 10 case studies were in California), in which the barriers are also classified as technical, business practices, or regulatory[119]. The barriers encountered by the case studies located in California are summarized in Table 45.

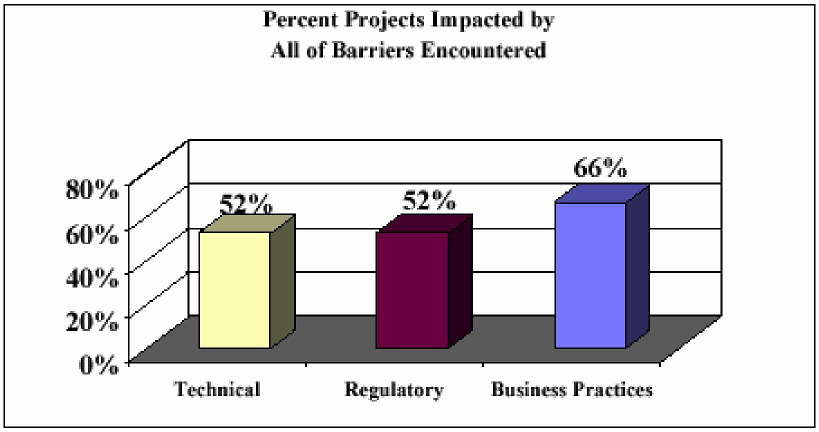
Table 46. Barriers Encountered by DG Case Studies in California[120]

Case	Technology	Technical	Regulatory	Business Practices
2-kW PV System	PV	∅	❍	∅
3-kW PV System	PV	∅	❍	∅
7.5-kW PV and Propane System	NG	∅	❍	∅
10-kW PV System	PV	❍	❍	❍
12-kW PV System	PV	❍	❍	∅
37-kW Gas Turbine	NG	∅	∅	∅
40 sites of 60-kW NG IC Systems	NG	∅	∅	∅
75-kW NG Microturbine	NG	∅	●	∅
132-kW PV System	PV	∅	∅	∅
2.1-MW Wind Turbines	W	∅	❍	∅

Key:
Project was stopped or prohibited from interconnection because of barrier ●
Project was delayed or more costly because of barrier ∅
Project was not hindered because of barrier ❍
NG= Natural Gas, PV=Photovoltaic Solar, W=Wind

Figure 30 illustrates the percentage of projects impacted by each of the three barrier categories for all 65 of the case studies. These barriers do not reflect consideration of technical issues from the utility point of view, but do function to illustrate the perceived impediments to DG implementation from a developer's point of view.[121]

Figure 30. Percent of Projects Encountering Barriers[122].



All but seven of the 65 case studies were impacted by at least one kind of barrier, and over half were hindered in each category. In California, only one was unaffected. The rest were delayed or costs increased, and one was prevented from being completed.

Endnotes

[1] For the purposes of this discussion, distributed generation is defined as small-scale generation, typically under 10 MW in capacity, inter-connected to the utility grid at distribution or sub-transmission voltages.
[2] "Benefits and Pricing Strategies for Services Provided by DG and DSM to the Distribution System," prepared by Energy and Environmental Economics on behalf of the ENERGY COMMISSION, forthcoming.
[3] This is illustrated by the fact that existing California ISO rules exempt generators under 10 MW from the ISO telemetry requirements placed on larger generators active in ISO markets. See also ISO Tariff Amendment 35 summarized in Appendix A.
[4] FERC (1996).
[5] The agreement with SCE called for Heritage Park to pay SCE full retail for the electricity generated but receives a discount on the thermal energy generated. This was actually an honest experiment on the part of SCE to see if the utility could profitably get into this business. Finally, they decided that they could not generate the power on site more cost effectively than bringing in wholesale power. The equipment consisted of two Tecogen 60 kW automotive derivative reciprocating engines.
[6] SCE is not required to purchase power for sites with more than 100 kW of capacity and had, in the past, resisted sale of power to the high school.
[7] At one point, there was the possibility of obtaining Turbec microturbine for free.
[8] An adjustment is also made for the line loss getting the power from the utility's generating station to the customer's site.
[9] The 2nd Law of Thermodynamics is a physical law that says that a heat engine needs to operate across energy potential and that the maintenance of this potential, in and of itself, requires energy or what is referred to as "the second law loss".
[10] Provided compliments of the United States CHP Association.
[11] Heat rate is the measure of efficiency and is calculated by dividing the prime mover's fuel consumption by the power that it generates. Heat rates are usually notated as to whether they are calculated with the lower or higher heating value of the fuel. Prime mover manufacturers tend to always publish heat rates of their machines based on the lower heat value of the fuel. They argue that this essentially holds all fuels constant. Gas meters read in higher heating value. To adjust from lower to higher heat rate for natural gas, divide by .9.
[12] Pounds per square inch – gage as opposed to psi or pounds per square inch-absolute. 14.7 psi pressure is equivalent to 0 psig.
[13] There are single effect absorption machines and double effect. The single effect uses twice the heat to produce the same amount of chilling as the double effect machine. However, the single effect machine can use low quality heat whereas the double effect machines require high-pressure steam (>100 psig). Double effect absorbers cannot be used with reciprocating engines.
[14] A compressor is a mechanical device that compresses a gas, in this case air prior to entering the combustor.
[15] The combustor is where fuel is added and the compressed mixture is heated to around 1600 F.
[16] The "quality" of heat typically refers to its temperature.
[17] SoCalGas' WACOG is their estimate of their cost of gas after interstate transmission has been paid on the California side of the border.
[18] This is the rate that distributed generation facility could actually avoid if generating and using their own power. There are fixed facilities charge that are assumed to be paid.
[19] These rates are retail rates not to be confused with wholesale or commodity costs.
[20] The three rate schedules presented here are the commercial/industrial rates provided by SCE. GS-2 is a demand rate available to customers whose billing demand exceeds 20 kW but has not exceeded 500 kW in any three months of the last twelve. TOU-8 is a mandatory time of use rate for customers whose billing demand has exceeded 500 kW for any three of the last twelve months. I-6 is an interruptible rate for customers who choose it but would otherwise qualify for TOU-8. I-6 is now closed to new customers and will cease to exist on December 31, 2002.
[21] Dollars are nominal.

[22] If Southern California Gas Company's WACOG is an indication of the long term price of gas ($2.50/mmbtu), then the actual replacement cost will be more like $41 or $42/mwhr. However, given the long term nature of the contracts, these prices will not be available to the consumers any time soon.
[23] Period assumed for the bonds is 15 years.
[24] This discussion has dwelled on the variable portion of Edison's GS-2 rate. The careful observer will note that no provision for transmission and distribution costs have been included in this figure. Edison collects only $.0008/kWh in variable costs for T&D. Most of the T&D costs have found their way into demand and facilities charges.
[25] SBX 2 78, the bill intended to provide relief to SCE.
[26] Gas and electricity bills are from October 1999 to September 2000.
[27] Equipment economic life is expected to be 10 years.
[28] Simple payback is reported here as a simple method to easily gauge economic performance. This approximation of performance starts to suffer as the simple paybacks extend beyond three years due to the time value of money. In such a case IRR becomes the necessary method by which to gauge performance.
[29] Under Edison's GS-2 rate for the period from December 2, 2001 and for three years except as noted.
[30] The term "cogeneration and combined heat and power are used interchangeably in this report.
[31] Interrupting when requested is requirement of the I-6 rate under which they were receiving power. Penalty rates of $7.20/kwh during periods when they use power during interruptions.
[32] Pounds per square inch –gage which indicates 14.7 pounds per square inch less than pounds per square inch – absolute.
[33] Thermal quality is the measure of the temperature of the thermal energy stream. With dry steam, thermal quality can also be measured in steam pressure or psig.
[34] Steam taken from the second pressure made available from the triple pressure housing.
[35] The original financial analysis of Dana Technologies is included here because it does an excellent job of comparing the various combustion turbine alternatives. A more contemporaneous analysis appears later that deals specifically with the installation that will ultimately be installed.
[36] This is value is low by today's standards. A more contemporaneous analysis of the small system will be found later in the text.
[37] This is not a realistic value that could be expected today if one hasn't already signed a power sales contract with the California Department of Water Resources or the California Power Authority.
[38] This scenario is added because the I-6 rate will end at the end of 2001.
[39] SoCalGas' WACOG is their estimate of their cost of gas after interstate transmission has been paid on the California side of the border.
[40] This the rate that distributed generation facility could actually avoid if generating and using their power. There are fixed facilities charges that are to be paid.
[41] Uplift includes the cost of ancillary services, transmission line loss, settlement costs, etc.
[42] These rates are retail rates not to be confused with wholesale or commodity costs.
[43] If Southern California Gas Company's WACOG is an indication of the long term price of gas ($2.50/mmbtu), then the actual replacement cost will be more like $41 or $42/MWhr. However, given the long term nature of the contracts, these prices will not be available to the consumers any time soon.
[44] This discussion has dwelled on the variable portion of Edison's I-6 rate. The careful observer will note that no provision for transmission and distribution costs have been included in this figure. Edison credits ($.000555/kwh) in variable costs for T&D. Most of the T&D costs have found their way into demand and facilities charges.
[45] The customer pays surcharges on power he generates as well as power he purchases.
[46] SBX 2 78, the bill intended to provide relief to SCE, which of course was not passed.
[47] It is anticipated that Paramount Petroleum will be grand fathered.
[48] 2004 - 2010
[49] After taxes
[50] Before taxes, debt service and after fixed maintenance.

[51] After taxes.
[52] Before taxes, debt service and after fixed maintenance.
[53] After taxes
[54] Before taxes, debt service and after fixed maintenance.
[55] The debt/equity ratio assumed in this analysis was 50%. The industry average debt equity ratio for integrated energy companies is 30% and for construction material providers is 64%.
[56] This is state-of-the-art technology.
[57] CEQA is the California Environmental Quality Act that requires an evaluation of environmental impacts.
[58] Under special project circumstances, the air district may be the lead agency. This is determined on a case-by-case basis.
[59] Certain types of projects are exempt from obtaining building permits, i.e., local agencies, state-owned buildings; however, projects should still be designed to comply with the building codes.
[60] Under the South Coast Air Quality Management District (SCAQMD) jurisdiction, some sources are RECLAIM facilities. Emission credits required by the RECLAIM program are referred to as RTCs or RECLAIM trading credits. Emission reduction credits (ERCs), as part of the New Source Review (NSR) permit program, may also be required for facilities.
[61] Excerpt from CARB webpage: www.arb.ca.gov/energy/dg/dg.htm
[62] The City's Planning and Development Services is open Monday through Thursday and alternating Fridays.
[63] The SCAQMD is open Tuesday through Friday.
[64] RECLAIM is the SCAQMD's "Regional Clean Air Incentives Market" program. Information regarding RECLAIM can be found on the agency's website: www.aqmd.gov/reclaim/reclaim.html.
[65] South Coast Air Quality Management District "Best Available Control Technology Guidelines, Part D – BACT Guidelines for Non-Major Polluting Facilities," October 20, 2000, page 60.
[66] Paramount is agreeing to use an ammonia analyzer to demonstrate continuous compliance.
[67] In other states, different emission factors and risk factors (OEHHA versus EPA) may be used.
[68] CARB web site with guidance document: www.arb.ca.gov/energy/dg/dg.htm.
[69] The Bay Area Air Quality Management District has a fee component that is based on heat rate, MMBtu/hr.
[70] Based on report titled "*Technical Alternatives and Economic Comparison – Heritage Park Aquatic Center/City of Irvine*". Assumes primarily planning/building departments, fire department and other non-air quality agency approvals, as needed.
[71] Assumes similar costs (for non-air quality approvals) associated with microturbine installation, in addition to air quality fees. Assuming one engine, air quality costs include permit fee, source test (as well as pre-test set-up costs), and consulting support (e.g., health risk assessment).
[72] Based on report titled "*Technical Alternatives and Economic Comparison – Paramount Petroleum.*" Assumes air quality costs (e.g., fees, consulting, testing) of approximately $20,000, and the remaining cost of $30,000 associated with the planning and building departments, as well as the South Coast AQMD (who serves as the lead agency for CEQA) and consulting support.
[73] Assumes that the permit costs for a microturbine would remain the same as the current because of the relatively straightforward approval process and of the future statewide certification program for microturbines.
[74] "Market Assessment of Combined Heat and Power in the State of California," prepared for the California Energy Commission and prepared by ONSITE SYCOM Energy Corporation. September 2, 1999.
[75] For the purposes of this discussion, distributed generation is defined as small-scale generation, typically under 10 MW in capacity, inter-connected to the utility grid at distribution or sub-transmission voltages.
[76] "Benefits and Pricing Strategies for Services Provided by DG and DSM to the Distribution System," prepared by Energy and Environmental Economics on behalf of the ENERGY COMMISSION, forthcoming.
[77] This is illustrated by the fact that existing California ISO rules exempt generators under 10 MW from the ISO telemetry requirements placed on larger generators active in ISO markets. See also ISO Tariff Amendment 35 summarized in Appendix A.
[78] FERC (1996).

[79] Transmission, sub-transmission and distribution voltage definitions from different sources may vary slightly. The voltage categories used in this report are derived from the California Energy Commission's on-line Energy Glossary (http://www.energy.ca.gov/glossary/).
[80] Knapp, Martin and Price (2000) provide a discussion of methods that can be applied to value the capacity deferral benefits of DG. See also Orans (1989) and Saunders, Warford and Mann, (1977).
[81] The use of the term "proponents" in this report refers broadly to researchers, manufacturers, trade and interest groups such as the Distributed Power Coalition of America (DPCA), and others in the electric power industry whose work supports an increased energy infrastructure reliance on DG.
[82] Alvarado, 2001.
[83] Aggregate DG control from an ISO or similar entity is entirely feasible particularly with larger (megawatt class) generators, given that they will already be required to install dedicated high-speed communication links to participate in the A/S market. The complexity of aggregating smaller generators (e.g. <500 kW) for a single application such as this increases with the number of DG needed and the state of the communications infrastructure.
[84] Allocation of costs and charges by the ISO is determined by the terms and conditions of the ISO tariff. These may not recognize all such DG benefits.
[85] Unpublished findings from a DOE study on the value of DG.
[86] Back-up generation is often installed with protective equipment that prevents it from synchronizing with the utility grid. This equipment would need to be adjusted for the generator to participate in the reserve market.
[87] See Appendix A for a description of recent changes to the ISO requirements for DG participation in AS markets.
[88] IEEE P1547.
[89] ENERGY COMMISSION, December 2000.
[90] UDCs include all entities providing distribution services, such as investor owned utilities (IOUs), municipal utilities, municipal utility districts, cooperative utilities, and irrigation districts.
[91] For the purposes of this discussion, distributed resources (DR) encompass both distributed generation (DG) and demand side management (DSM) technologies, including both active load management activities and passive energy efficiency measures.
[92] Phone conversation with Roger Dugan, Electrotek Concepts, June 22, 2001. The authors believe that typically distribution outages are responsible for 75% - 90% of customer outages based on their consulting work with numerous utilities and the Electric Power Research Institute.
[93] Dugan, R., and Ball, G., *"Engineering Handbook for Dispersed Energy Systems on Utility Distribution Systems,"* Report No. TR-105589, Electric Power Research Institute, Nov. 1995.
[94] For an example of PBR criteria and a recent reward settlement between the California Public Utilities Commission and San Diego Gas & Electric, see CALIFORNIA PUBLIC UTILITIES COMMISSION Energy Resolution E-3730, May 3, 2001 (http://www.California Public Utilities Commission.ca.gov/).
[95] See Energy and Environmental Economics, *Task 2.3: Engineering and Institutional Limitations of DG as a Means to Provide Transmission and Distribution (T&D) Services,* prepared for the California Energy Commission, forthcoming.
[96] As in the case of losses, an inadequately sized line can exacerbate a voltage drop problem because of its higher impedance.
[97] Power factor is the ratio of real power to *apparent* power, where apparent power is the vector sum of real and reactive powers. Therefore, a power factor of 1 (or unity) includes no reactive power.
[98] Detroit Edison, *Detroit Edison Has New Tool to Control Peak Electric Demand*, June 12, 1998, http://www.dteenergy.com/aboutdte/news/peaks.html.
[99] The asymmetric information and rent-seeking link is well documented. See for example, Laffont & Tirole (1993), A Theory of Incentives in Procurement and Regulation, MIT Press, and London, page 76.
[100] For example, VOS is now being used to justify some utility projects. In New York, NYPSC denied an $30 million transmission project because of insufficient VOS impact. In the 1999 General Rate Case for PG&E, the Commission stated in several places a preference for justifying reliability improvement

projects on customer VOS [D. GRC [D.00-02-046]*"A missing piece of PG&E's analysis of its customers' service expectation is an assessment of their willingness to pay for desirable improvement in reliability or in other aspects of service." (p.44)*

[101] See for example Laffont & Tirole, (op cit), p. 33.
[102] There are several good reviews of the PBR topic -- for example, see EPRI, *Rate Design: Traditional and Innovative Approaches*, CU-6886, Research Project 2343-4, Palo Alto, CA, July 1990.
[103] Milgrom and Roberts (1992), Economics, Organization and Management, Prentice-Hall, p. 595.
[104] Equipment replacement expenditures relative scale is based on budget allocation experience with several utilities. Most types of distribution equipment have relatively long service lives. Under normal conditions, most transformers and feeders last in excess of 40 years. Overloading can severely limit this lifetime, though. Some kinds of equipment are not sensitive to power level (wooden poles depend more on local environment and ambient conditions, for example).
[105] Woo, Heffner, Horii, Lloyd (1997), "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution", *IEEE Transaction on Power Systems*. PE-493-PWRS-0-12-1997.)
[106] Including the use of pre-subscribed posted tariffs with only the price determined by auction.
[107] There are a very limited number of examples of price posting for capacity related services. BC Hydro, for example, has posted wholesale transmission rates differentiated by area to reflect the long run costs of future capital upgrades. Orange and Rockland in New York offered an optional curtailable load credit with different credit levels for two distribution areas in their service territory.
[108] EPRI. *Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District.* TR-100487, Palo Alto, CA, May 1992.
[109] There are no comprehensive reviews of the potential for DR to offset distribution capacity costs specifically. However, there are expectations that DR will provide a significant amount of new electric capacity. A study by the Electric Power Research Institute (EPRI) indicated that by 2010, 25 % of the new generation will be distributed, and a study by the Natural Gas Foundation concluded that this figure could be as high as 30 % (www.distributed-generation.org). The goal stated in the DOE 'Strategic Plan for Distributed Energy Resources' is 20% of new capacity by 2010 (available at http://www.eren.doe.gov/der/). Regulatory treatment of the impact of DG penetration on utility revenues is already in place. For example, legislation has limited claims of stranded wires assets until loss of load has exceeded 7.5% and 10% in New Jersey and Massachusetts, respectively.

[110] See Energy and Environmental Economics, *Task 2.1 Final Report: Transmission System Services Provided by Distribution Level Distributed Generation*, February 9, 2001, and *Task 2.2 Final Report: Benefits and Pricing Strategies for Services Provided by DG and DSM to the Distribution System*, June 22, 2001. Both reports submitted to the California Energy Commission.
[111] See, for example, California Energy Commission, Siting Committee Recommendations Regarding Distributed Generation Interconnection Rule, P700-00-004, May 2000 and ENERGY COMMISSION Recommendation on DG Interconnection Rules, P700-00-006, June 2000.
[112] Operating temperatures for fuel cells vary by fuel technology type.
[113] Some claim that fuel cells are capable of tracking load changes. A recent DG internet discussion group posting from Alan Cisar from Lynntech, Inc. stated "Fuel cells can track load changes at very high rates. Transitions from idle to nearly full load in less than 1/120 second (less than half a cycle at 60 Hz) have been demonstrated. The problem is the fuel supply. Unless the system has a supply of hydrogen, it is running on a reformed hydrocarbon fuel (natural gas, propane, gasoline, diesel, etc.). The fuel processing equipment typically has a far slower response, and that sets the limit on a system's ability to respond." Distributed Generation Discussion Group, November 27, 2000, http://www.egroups.com/list/distributed-generation.
[114] IEEE STD 519-1992*, Recommended Practices and Requirements for Harmonic Control in Electric Power Systems*, Institute of Electrical and Electronic Engineers, Piscataway, NJ. April 1992.
[115] *Ibid.*
[116] *Ibid*.
[117] Interconnection requirements discussion derived from Gridwise Engineering Company, Energy and Environmental Economics, and Endecon Engineering*, Cost-Benefit Analysis of Distributed Generation,*

Phase I Engineering Study, consultant report prepared for Oklahoma Municipal Power Authority, September 2000.

[118] California Public Utilities Commission, Rule 21 Model Tariff Language, Attachment A: Decision 00-12-037, Decision Adoption Interconnection Standards, Dec 21, 2000.

[119] Alderfer, P., M. Eldridge and T. Starrs, *Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects*, NREL/SR-200-28053, May 2000. The barriers identified in this study represented the developer's point of view. The study did not report on utility concerns underlying the identified barriers.

[120] Reproduced from Alderfer, *et al*.

[121] Aldefer, *et al.*, p. 2.

[122] Reproduced from Alderfer, *et al*.